NATIONAL GRID USA

ANNUAL REPORT 2009

PRICEWATERHOUSECOOPERS

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Report of Independent Auditors

To the Stockholder and Board of Directors
National Grid USA:

In our opinion, the accompanying consolidated balance sheets and statements of capitalization and the related consolidated statements of income, of comprehensive income, of retained earnings and of cash flows present fairly, in all material respects, the financial position of National Grid USA and its subsidiaries at March 31, 2009 and 2008, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note A to the financial statements, the Company changed the manner in which it accounts for income taxes effective April 1, 2007.

PricewaterhouseCoopers LLP

October 27, 2009

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

(in millions of dollars)	March 31, 2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 424.9	$ 1,169.9
Restricted cash and special deposits	197.3	91.2
Accounts receivable	2,531.0	2,474.5
Unbilled revenues	718.9	941.2
Allowance for uncollectible accounts	(392.8)	(299.8)
Gas in storage, at average cost	479.4	336.5
Materials and supplies, at average cost	199.8	389.3
Derivative contracts	51.5	169.5
Regulatory assets	683.4	539.5
Derivative contracts - regulatory asset	328.5	76.3
Prepayments	171.9	259.2
Current deferred income taxes	218.5	188.5
Other	8.0	58.8
Discontinued assets held for sale	30.0	3,025.4
Total current assets	5,650.3	9,420.0
Equity investments and other	469.9	504.2
Property plant and equipment, net	18,322.9	17,410.2
Deferred charges		
Regulatory assets:		
Regulatory assets	5,569.3	5,435.4
Derivative contracts	231.5	147.4
Goodwill	7,372.4	7,326.5
Intangible assets, net of amortization	165.5	230.9
Derivative contracts	20.1	132.1
Other	216.1	276.1
Total deferred charges	13,574.9	13,548.4
Total assets	$ 38,018.0	$ 40,882.8

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,			
		2009		2008
LIABILITIES AND CAPITALIZATION				
Current liabilities				
Accounts payable	$	1,269.8	$	1,620.7
Commercial paper		-		1,115.0
Current portion of long-term debt		471.4		992.6
Taxes accrued		543.8		301.0
Customer deposits		107.6		107.6
Interest accrued		211.2		199.8
Regulatory liabilities		215.0		205.4
Regulatory liabilities-Derivatives		46.0		171.4
Intercompany money pool		1,975.8		1,112.0
Notes payable - other		-		298.0
Current portion of accrued Yankee nuclear plant costs		14.8		23.2
Derivative contracts		331.2		81.8
Discontinued current liabilities held for sale		12.7		1,860.8
Other		510.3		479.4
Total current liabilities		5,709.6		8,568.7
Deferred credits and other liabilities				
Regulatory liabilities:				
Regulatory liabilities		1,210.1		1,186.6
Removal costs recovered		1,392.2		1,305.9
Derivative accounts		9.3		113.4
Assets retirement obligations		67.7		67.6
Deferred income taxes		2,344.0		2,427.3
Postretirement benefits and other reserves		3,776.8		2,864.7
Environmental remediation costs		1,382.1		1,282.9
Derivatives contracts		252.2		150.6
Other		1,108.6		839.1
Total Deferred credits and other liabilities		11,543.0		10,238.1
Capitalization				
Common stock ($.10 par value)		-		-
Paid in capital		13,043.5		14,043.4
Retained earnings		2,351.7		1,875.5
Accumulated other comprehensive income (loss)		(1,043.7)		(512.6)
Total common shareholders' equity		14,351.5		15,406.3
Minority interest in subsidiaries		18.2		19.3
Cumulative preferred stock, par value $100 per share		34.8		34.8
Long-term debt		5,136.5		5,391.2
Long-term debt to affiliates		1,224.4		1,224.4
Total capitalization		20,765.4		22,076.0
Total capitalization and liabilities	$	38,018.0	$	40,882.8

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, 2009	2008
Revenues		
Gas Distribution	$ **7,321.6**	$ 5,694.6
Electric Services	**8,194.6**	7,610.8
Other	**163.2**	95.2
Total Revenues	**15,679.4**	13,400.6
Operating expenses		
Purchased gas for sale	**4,775.9**	3,804.9
Electricity purchased	**3,544.2**	3,492.8
Contract termination charges and nuclear shutdown charges	**24.6**	40.0
Operation and maintenance	**3,759.3**	2,801.3
Depreciation, depletion and amortization	**803.0**	642.5
Amortization of regulatory assets, stranded costs and rate plan deferrals	**553.5**	531.9
Other taxes	**905.2**	630.6
Total Operating Expenses	**14,365.7**	11,944.0
Operating income	**1,313.7**	1,456.6
Other income and (deductions)		
Interest on long-term debt	**(312.4)**	(328.7)
Other interest, including affiliate interest	**(266.7)**	(176.4)
Other	**38.9**	14.7
Total other income and (deductions)	**(540.2)**	(490.4)
Income taxes	**320.5**	345.3
Dividend on preferred stock of subsidiaries	**1.3**	1.8
Total continuing operations	**451.7**	619.1
Income from discontinued operations, net of tax expense of $17.5 million and $30.2 million	**24.6**	27.8
Gain on sale of discontinued businesses, net of tax	**-**	15.2
Income from discontinued operations, net of tax	**24.6**	43.0
Net income	$ **476.3**	$ 662.1

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, 2009	2008
Net income	$ 476.3	$ 662.1
Other comprehensive income (loss), net of taxes:		
Unrealized (gains) losses on investments	(15.4)	(13.6)
Unrealized (gains) losses on hedges	2.4	-
Change in pension and other postretirement obligations	(517.7)	(100.5)
Reclassification adjustment for gains (losses) included in net income	(0.4)	3.2
Total other comprehensive income (loss)	(531.1)	(110.9)
Change in accumulated other comprehensive income (loss)	$ (54.8)	$ 551.2
Related tax expense (benefit):		
Unrealized (gains) losses on investments	(10.3)	(9.1)
Unrealized (gains) losses on hedges	1.6	-
Change in pension and othr postretirement obligations	(345.3)	(67.0)
Reclassification adjustment for gains (losses) included in net income	(0.3)	2.1
Total tax expense (benefit)	$ (354.2)	$ (74.0)

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statements of Retained Earnings

(in millions of dollars)	For the years ended March 31, 2009	2008
Retained earnings at beginning of period	$ 1,875.5	$ 1,550.0
Adoption of new accounting standard FIN 48	-	(8.4)
Adjusted balance at beginning of period	1,875.5	1,541.6
Net income	476.3	662.1
Dividends on preferred stock	(0.1)	(0.1)
Return of capital to parent company	-	(327.7)
Other	-	(0.4)
Retained earnings at end of period	$ 2,351.7	$ 1,875.5

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, 2009	2008
Operating activities:		
Net income	$ 476.3	$ 662.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Net (income) loss from discontinued operations	(24.6)	(43.0)
Depreciation and amortization	803.0	642.5
Amortization of stranded costs and rate plan deferrals	553.5	531.9
Income from equity investments	(22.1)	(8.6)
Dividends from equity investments	0.3	7.5
Merger related and other non-cash charges	118.8	(47.5)
Provision for deferred income taxes and investment tax credits	(743.3)	(76.6)
Net pension and other post retirement expense/cash payment	(352.7)	(271.8)
Changes in operating assets and liabilities:		
Accounts receivable, net	294.6	(803.9)
Materials and supplies	(75.3)	357.7
Accounts payable and accrued expenses	(120.6)	199.8
Environmental payments	(171.0)	(64.9)
Other, net	19.0	66.9
Net cash provided by operating activities	755.9	1,152.1
Investing activities:		
Plant expenditures	(1,516.3)	(1,105.6)
Acquisitions	-	(7,545.1)
Net proceeds from sale of subsidary and assets	2,989.3	313.8
Change in restricted cash	(149.7)	43.9
Other, net	(45.2)	40.9
Net cash used in investing activities	1,278.1	(8,252.1)
Financing activities:		
Dividends paid on common and preferred stock	(0.1)	(41.8)
Dividends paid on common stock of minority interests	-	(2.1)
Return of capital to parent company	-	(327.7)
Redemption of preferred stock	-	(18.0)
Buyback of minority interest common stock	-	(1.3)
Capital contribution from parent for acquisitions	-	7,545.1
Buyback of common stock	(1,000.0)	(1,075.5)
Payment of long-term debt	(923.3)	-
Proceeds from long-term debt	160.5	147.3
Increase in intercompany money-pool	863.8	107.5
Net (decrease) increase in external short-term debt	(1,412.9)	1,130.6
Net cash provided by financing activities	(2,312.0)	7,464.2
Net increase in cash and cash equivalents	(278.0)	364.2
Cash flow from discontinued operations - Operating activities	(28.8)	(2.0)
Cash flow from discontinued operations - Investing activities	(13.2)	(20.1)
Cash flow from discontinued operations - Financing activities	(425.0)	(9.5)
Cash transferred from KeySpan	-	555.4
Cash and cash equivalents, beginning of period	1,169.9	281.9
Cash and cash equivalents, at end of period	$ 424.9	$ 1,169.9
Supplemental disclosures of cash flow information:		
Interest paid	$ 370.3	$ 458.3
Taxes paid	$ 938.4	$ 413.1

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,			
	2009	2008	**2009**	2008
Common Shareholders' Equity	**Shares Issued**		**Amounts**	
Common stock, $0.10 par value	1,000	1,000	$ -	$ -
Additional Paid in Capital			13,043.5	14,043.4
Retained earnings			2,351.7	1,875.5
Accumulated other comprehensive loss			(1,043.7)	(512.6)
Total Common Shareholders' Equity			14,351.5	15,406.3
Minority Interest in Subsidiaries			18.2	19.3
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	Various	3.55% - 5.51%	93.2	159.1
Notes payable	4.65% - 9.75%	4.65% - 9.75%	2,690.9	3,456.3
Total Medium and Long-Term Debt			2,784.1	3,615.4
Gas Facilities Revenue Bonds	Variable	Variable	230.0	230.0
	4.70% - 6.95%	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%	5.15%	108.0	108.0
Electric Facility Revenue Bonds	5.30%	5.30%	47.4	47.4
Total Promissory Notes to LIPA			155.4	155.4
First Mortgage Bonds	6.34% - 9.63%	5.72% - 10.25%	133.4	205.1
State Authority Financing Bonds	Variable	Variable	1,199.7	1,219.9
Industrial Development Revenue Bonds	5.25%	5.25%	128.3	128.3
Committed Facilities	Variable	Variable	543.0	382.5
Inter-Company Notes	5.52%	5.52%	1,224.4	1,224.4
Subtotal			6,808.8	7,571.5
Fair value adjustments			23.5	36.7
Less: current maturities			471.4	992.6
Total Long - Term Debt			6,360.9	6,615.6
Total Capitalization			$ 20,765.4	$ 22,076.0

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 A - SIGNIFICANT ACCOUNTING POLICIES

1. 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, and sale of both electricity and 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. On August 24, 2007, the Company acquired KeySpan Corporation (KeySpan and the KeySpan Acquisition) including its subsidiaries (See Note L "Acquisitions").

The Company's electricity and gas distribution subsidiaries serve over six million customers in New York State, Massachusetts, Rhode Island and New Hampshire. The Company's New England subsidiaries include: New England Power Company (NEP), The Narragansett Electric Company (Narragansett), Massachusetts Electric Company (Mass Electric), Nantucket Electric Company (Nantucket Electric), Granite State Electric Company (Granite State), Boston Gas Company, Colonial Gas Company, Essex Gas Company and EnergyNorth Natural Gas Inc. The Company's New York subsidiaries include: Niagara Mohawk Power Corporation (Niagara Mohawk), KeySpan 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 long-term service contracts having remaining terms that range from one to five years and power purchase agreements having remaining terms that range from five to nineteen years.

Company subsidiaries also owned or leased and operated the 2,200 MW Ravenswood Facility located in Queens, New York, and the 250 MW combined-cycle Ravenswood Expansion. Collectively the Ravenswood Facility and Ravenswood Expansion are referred to as the "Ravenswood Generating Station." The New York Public Service Commission (NYPSC) required the divestiture of the Ravenswood Generating Station as a condition for their approval of the KeySpan Acquisition, and as a result, the Ravenswood Generating Station was sold in August 2008. Accordingly, the Ravenswood Generating Station is reflected as discontinued operations in the financial statements. Additionally during fiscal year 2009, the Company sold most of its unregulated subsidiaries engaged in the construction, leasing, and ownership of telecommunications infrastructure, and in engineering and consulting services. These subsidiaries are also classified as discontinued operations.

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 that own generating facilities that have been decommissioned.

2. Basis of Presentation

The Company's accounting policies conform to generally accepted accounting principles in the United States of America (US 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 4 "Accounting for the Effects of Rate Regulation").

The consolidated financial statements include the accounts of the Company and all of its wholly-owned subsidiaries and entities for which the Company has control. Investments in which the Company can exercise significant influence over the operations of the investee (generally where the Company owns 20% of the investee but not in excess of 50%) are accounted for under the equity method of accounting. All intercompany transactions and balances between consolidated subsidiaries have been eliminated in consolidation. The Consolidated Statement of Income include the results of acquired operations since the date of acquisition, the most significant being the acquisition of KeySpan on August 24, 2007.

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.

Upon acquisition, KeySpan aligned certain of its accounting policies with NGUSA's policies including certain assumptions underlying the calculations for its pension and other postretirement reserves where appropriate. Additionally, KeySpan adjusted certain assumptions underlying the calculations for its environmental reserve to align those assumptions with NGUSA's environmental reserve assumptions where appropriate. (See Note L "Acquisitions" for additional details on the accounting policy matters).

3. Use of Estimates

The preparation of financial statements in conformity with US 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.

4. 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 the NYPSC, the New Hampshire Public Utilities Commission (NHPUC), the Massachusetts Department of Public Utilities (MADPU) and the Rhode Island Public Utility Commission (RIPUC). Our financial statements reflect the ratemaking policies and actions of these regulators in conformity with US GAAP for rate-regulated enterprises. Our electric generation subsidiary is not subject to state rate regulation, but is subject to Federal Energy Regulatory Commission (FERC) regulation.

All of our transmission and distribution regulated utilities are subject to the provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards

(SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." 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. (See Note B "Rate and Regulatory").

5. Goodwill
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 purchase method of accounting, the application of which includes the recognition of goodwill. Goodwill was approximately $7.4 billion at March 31, 2009 and 2008.

During the fiscal 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 $49.1 million. See Note L "Acquisitions" for additional details.

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," the Company reviews its goodwill annually for impairments in the fourth quarter of its fiscal year or whenever indicators of impairment are present. The Company utilized a discounted cash flow approach incorporating its most recent business plan forecasts in the performance of the annual goodwill impairment test. The result of the annual analysis determined that no impairment adjustment to goodwill carrying value was required.

6. 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 FERC and the 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, 2009 and 2008 was $718.9 million and $941.2 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. To mitigate the effect of fluctuations from normal weather on our financial position and cash flows, we may enter into weather related derivative instruments from time to time.

LIPA Agreements: KeySpan and LIPA are parties of three major long-term 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 all aspects of the fuel supply for our Long Island generating facilities, as well as all aspects of the capacity and energy owned by or under contract to LIPA pursuant to the Energy Management Agreement (the EMA). 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 KeySpan'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.

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 measured results of the Customer Satisfaction performance metric were below minimum threshold for the 2006 and 2007 contract years. The 2008 results were released, but LIPA and KeySpan had a dispute as to interpretation: LIPA asserted that KeySpan had failed the metric in 2008; however, KeySpan took the position that it satisfied the 2008 threshold. LIPA and KeySpan entered into settlement negotiations to resolve this dispute and the parties have reached an agreement in principle to settle this matter. Under the salient terms of the settlement, (a) LIPA will waive its claim of default under the MSA, (b) KeySpan will remit a settlement payment in the sum of $1million, (c) the penalty for failing the Customer Satisfaction metric will be increased from $1 million to $2 million, (d) KeySpan will transfer certain assets that are not critical to KeySpan's business to LIPA in advance of an obligation that manifests at MSA expiration in 2013, and (e) KeySpan will evaluate and process LIPA information services initiatives pursuant to its governance policies. The parties have also agreed to revisions to the Customer Satisfaction metric that change (a) how performance is measured, (b) the vendors providing the survey services for the metric, and (c) how penalties are assessed. The settlement will not have a material impact on KeySpan's financial statements. It is anticipated that the settlement documents will be executed by the parties before the end of calendar year 2009 and forwarded to the New York State Comptroller and Attorney General for approval.

In addition, 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 provides incentives and penalties that can total $4 million annually for the maintenance of the output capability and the efficiency of the generating facilities.

Pursuant to the EMA, the Company (i) procures and manages fuel supplies for LIPA to fuel KeySpan's Long Island based generating facilities; (ii) performs off-system capacity and energy purchases on a least-cost basis to meet LIPA's needs; and (iii) makes off-system sales of output from the Long Island based generating facilities and other power supplies either owned or under contract to LIPA. In exchange for these services we earn an annual fee of $1.5 million. LIPA is entitled to two-thirds of the profit from any off-system energy sales arranged by us. In addition, the EMA provides incentives and penalties that can total $5 million annually for performance related to fuel purchases and off-system power purchases. The original term for the fuel supply service described in (i) is 15 years, expiring May 28, 2013 and the original term for the off-system purchases and sales services described in (ii) and (iii), collectively, "Power Supply Management Services" was eight years, expiring May 28, 2006. The term for the Power Supply Management Services has been extended several times, most recently in 2007 when the parties amended the EMA to extend the term for such services until December 31, 2009, provided that LIPA shall have the right to terminate the Power Supply Management Services at any time upon 60 days prior notice.

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 other non current liabilities – other on the Consolidated Balance Sheet totaling $25.3 million as of March 31, 2009. This balance represents primarily unearned revenues for service contracts and is generally amortized to income over a one year period.

7. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. Property, plant and equipment related to KeySpan and its subsidiaries is stated at original cost less accumulated depreciation up to the date of acquisition. Accumulated depreciation for KeySpan and its subsidiaries reflects additions to the reserve balance from the date KeySpan was acquired. 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 (AFUDC) (See Item 8 "AFUDC" below). 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 $324.8 million and $312.2 million at March 31, 2009 and 2008, respectively, and associated amortization of $270.0 million and $236.5 million at March 31, 2009 and 2008, respectively.

	At March 31, 2009	2008
(in millions of dollars)		
Property Plant and Equipment		
Electric plant	$ **13,412.9**	$ 12,759.5
Gas plant	**8,799.2**	8,182.7
Common and other plant	**777.9**	712.8
Construction work-in-process	**638.0**	642.1
Total utility plant	**23,628.0**	22,297.1
Less: accumulated depreciation and amortization	**(5,341.6)**	(4,924.0)
Net property plant and equipment	**18,286.4**	17,373.1
Gas production	**42.2**	39.1
Less: depletion	**(5.7)**	(2.0)
Net gas production plant	**36.5**	37.1
Total Plant	$ **18,322.9**	$ 17,410.2

8. AFUDC

The Company capitalizes AFUDC as part of construction costs in amounts equivalent to the cost of funds devoted to plant under construction for its regulated businesses. AFUDC represents the composite interest and equity costs of capital funds used to finance that portion of construction costs not yet eligible for inclusion in rate base. AFUDC is capitalized in "Property, plant and equipment, net" with offsetting credits to "other interest, including affiliate interest" and "other income and (deductions)." This method is in accordance with established rate-making practices under which our utility subsidiaries are permitted to earn a return on, and the recovery of, prudently incurred capital costs through their ultimate inclusion in rate base and in the provision for depreciation. AFUDC rates vary by Company and regulatory jurisdiction.

Capitalized interest for the year ended 2009 and 2008 was $8.3 million and $9.1 million respectively and is reflected as a reduction to interest expense.

9. Depreciation and Amortization

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. The Company recovers cost of removal through rates charged to customers as a portion of depreciation expense. At March 31, 2009 and 2008, the Company had cumulative costs recovered in excess of costs incurred totaling $1.4 billion and $1.3 billion, respectively. This amount is reflected as a regulatory liability.

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

	Fiscal Years Ended March 31,	
	2009	2008
Asset Category:		
Electric	32	32
Gas	35	34
Common	18	22

We also had $1.38 billion and $1.32 billion of other property at March 31, 2009 and 2008, respectively, consisting of $638.0 million and $642.1 million at March 31, 2009 and 2008, respectively, of construction work in progress with the remaining assets held by our corporate service subsidiary and our non regulated subsidiaries. These assets consist largely of land, buildings, office equipment, furniture, vehicles, computer and telecommunications equipment and systems. These assets have depreciable lives ranging from 3 to 40 years.

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.

Regulatory assets, including those covered by contract termination charges, are amortized in accordance with the provisions of the regulated subsidiaries' rate settlement agreements and, therefore, are not necessarily amortized on a straight-line basis. NEP and Niagara Mohawk had deferred certain costs related to deregulation, including purchased power contract buyouts, and losses on the sale of generation assets as a regulatory asset (See Note B "Rates and Regulatory"). Niagara Mohawk's costs are being amortized unevenly over ten years with larger amounts being amortized in the latter years, consistent with authorized recovery through rates.

10. Cash and Cash Equivalents
The Company classifies short-term investments with an original maturity of three months or less as cash equivalents.

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

12. Income and Excise Tax
Federal and State income taxes are recorded under the provisions of SFAS No. 109 "Accounting 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. Effective April 1, 2007, the Company implemented FASB issued FIN 48 "Accounting for Uncertainty in Income Taxes – an interpretation of FASB No. 109" 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. For the twelve months ended March 31, 2009 and 2008 excise taxes collected and paid were $117.4 million and $78.9 million, respectively. Excise taxes associated with KeySpan's operations are reflected form the date of acquisition – August 24, 2007.

13. Derivatives

We employ derivative instruments to hedge a portion of our exposure to commodity price risk, interest rate risk and weather fluctuations. 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.

Firm Sales Derivatives 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 SFAS 71, "Accounting for 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 Sheet. 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.

Physically-Settled Commodity Derivative Instruments. 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 SFAS 133 as normal purchases. SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 149, "Amendment of Statement 133 Derivative Instruments and Hedging Activities" (collectively, SFAS 133). As such, these contracts are recorded on the Consolidated Balance Sheet at fair market value. However, since such contracts were executed for regulated utility customers, and pursuant to the requirements of SFAS 71, changes in the fair market value of these contracts are recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheet.

Financially-Settled Commodity Derivative Instruments. We 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 SFAS 133. 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 Sheet, 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 Sheet at fair value, with all changes in fair value reported in earnings.

Interest Rate Derivative 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 SFAS 133. Hedging transactions that effectively convert the terms of underlying debt obligations from variable to fixed are considered cash flow hedges.

14. Comprehensive Income

Comprehensive income is the change in the equity of a company, not including those changes that result from shareholder transactions. While the primary component of comprehensive income is reported as net income or loss, the other components of comprehensive income relate to changes in SFAS 158, "Employers' 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 D "Accumulated Other Comprehensive Income (Loss)").

15. Recent Accounting

In March 2008, the FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities." This Statement amends and expands the disclosure requirements of SFAS 133 with the intent to provide users of financial statements with an enhanced understanding of (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. This Statement requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses of derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. This Statement became effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. NGUSA adopted the new disclosure requirements for the March 31, 2009 and 2008 reporting periods. This Statement had no impact on results of operations, financial position or cash flows. (See Note E "Derivative Contracts and Fair Value Measurements" for the new disclosures)

In February 2007, the FASB issued SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This statement requires a business entity to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. An entity may decide whether to elect the fair value option for each eligible item on its election date, subject to certain requirements described in the statement. This statement became effective as of the beginning of each reporting entity's first fiscal year that begins after November 15, 2007. The Company has not elected the fair value method.

In December 2007, the FASB issued SFAS 141R "Business Combinations." The objective of SFAS 141R is to improve the relevance and comparability of the financial information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree; recognizes and measures the goodwill acquired in business combination; and determines what information to disclose. This Statement shall be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. This Statement has no impact on the Company's current results of operations, cash flows or financial position.

In December 2007, the FASB issued SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" – an amendment of Accounting Research Bulletin 51 "Consolidated Financial Statements." The objective of SFAS 160 is to improve the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 became effective for fiscal years and interim periods within those fiscal years, beginning on or after December 15, 2008. The adoption of SFAS 160 is not expected to have a material impact on the company's results of operations, cash flows or financial position.

On September 15, 2006, the FASB issued SFAS 157 "Fair Value Measurements." This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value. SFAS 157 expands the disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The disclosures focus on the inputs used to measure fair value, the recurring fair value measurements using significant unobservable inputs and the effect of the measurement on earnings (or changes in net assets) for the period. The guidance in SFAS 157 also applies for derivatives and other financial instruments measured at fair value under Statement 133 at initial recognition and in all subsequent periods. This Statement is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The adoption of SFAS 157 had no impact on the Company's results of operations financial position or cash flow (See Note E "Derivatives and Fair Value Measurements" for the new disclosures)

16. Reclassifications

Certain amounts from prior years have been reclassified on the accompanying consolidated financial statements to conform to the fiscal 2009 presentation. Additionally, the Company made the following classification adjustments as of the year ended March 31, 2008. In order to recognize the fact that commodity hedging relationship costs will be recovered from rate payers in futures periods, such costs are now classified as regulatory assets and liabilities rather than as other comprehensive income. Other immaterial adjustments, including the proper classification of preferred stock dividends within net income have also been made.

17. Equity Investments and Other
Certain subsidiaries own as their principal assets, investments (including goodwill), 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. Additionally, the Company has corporate assets recorded on the Consolidated Balance Sheet representing funds designated for Supplemental Executive Retirement Plans. 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 Technical Bulletin 85-4 "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 Statement of Income - other income and (deductions) concurrent with the change in the value of the underlying assets.

18. 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 $47.9 million and $288.1 million at March 31, 2009 and 2008, respectively, which is recorded in materials and supplies on the consolidated balance sheet. (See Note L "Acquisitions" for further discussion on emission allowance credit) On a quarterly 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. The existence of the market and the ability to realize the recorded value of the allowances as of period end demonstrates that no impairment was necessary.

NOTE B – RATE AND REGULATORY

The Company applies the provisions of the SFAS No. 71, "Accounting for Certain Types of Regulation," which requires regulated entities, in appropriate circumstances, to establish regulatory assets or liabilities, and thereby defer the income statement impact of certain charges or revenues because they are expected to be collected or refunded through future customer billings.

The Company is earning a return on a significant number of regulatory assets. Additionally, for those regulatory items for which cash expenditures have been made or for which cash has been collected, the Company records 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 the Company's costs and investments and it should continue to apply the provisions of SFAS 71. If the Company could no longer apply SFAS 71, the resulting charge would be material to the Company's reported financial condition and results of operations. The following table details the various categories of regulatory assets and liabilities:

(in millions of dollars)	March 31, 2009	2008
Regulatory assets included in accounts receivable:		
Rate adjustment mechanisms	$ 59.2	$ 106.8
Current portion of regulatory assets:		
Derivative and swap contracts	328.5	76.3
Purchase power obligations (Note A. 13)	4.0	3.1
Pension and post-retirement benefit plans	89.3	39.6
Yankee nuclear decommissioning costs	26.2	31.8
Merger rate plan stranded costs	502.5	410.9
Other	61.4	54.1
	1,011.9	615.8
Current portion of regulatory liabilities:		
Derivative and swap contracts	(46.0)	(171.4)
Rate adjustment mechanisms	(166.2)	(140.2)
Other	(48.8)	(65.2)
	(261.0)	(376.8)
Total net miscellaneous regulatory assets (liabilities) current	810.1	345.8
Regulatory assets:		
Stranded costs	981.0	1,490.1
Purchase power obligations	20.6	116.4
Derivative and swap contracts	231.5	147.4
Regulatory tax asset	234.6	162.8
Deferred environmental restoration costs	1,706.2	1,500.2
Pension and post-retirement benefit plans	1,908.7	1,773.3
Yankee nuclear decommissioning costs	80.9	91.9
Loss on reacquired debt	51.6	61.5
Long-term portion of standard offer under-recovery	53.4	51.3
Storm cost recoveries	210.3	-
Other	322.0	187.9
	5,800.8	5,582.8
Regulatory liabilities:		
Removal costs recovered (Note A. 9)	(1,392.2)	(1,305.9)
Stranded costs and CTC related	(181.9)	(156.6)
Pension and post-retirement plans fair value deferred gain	(207.9)	(385.7)
Interest saving deferral	(92.5)	(92.5)
Environmental response fund and insurance recoveries	(97.2)	(118.5)
Storm costs reserve	(21.4)	(44.1)
Derivative instruments	(9.3)	(113.4)
Other	(609.2)	(389.2)
	(2,611.6)	(2,605.9)
Total net miscellaneous regulatory assets non-current	3,189.2	2,976.9
Net miscellaneous regulatory assets	$ 3,999.3	$ 3,322.7

Stranded costs: Certain regulatory assets, referred to as stranded costs, resulted from major fundamental changes occurring in the public utility 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.

Storm costs: On December 11 and 12, 2008, a significant ice storm in Upstate New York, Massachusetts and New Hampshire which affected portions of Niagara Mohawk, Mass Electric and Granite State's service territories, severely damaging parts of the electric distribution system and causing numerous power outages. At its peak on December 12, there were approximately 0.5 million customers without service. Certain storm restoration costs may be included in the deferral account for recovery. The Company is 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 Company recorded a deferral of $110.2 million related to the December storm. At March 31, 2009, $210.3 million was the total storm cost recoveries recorded in the regulatory assets.

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.

Purchased power obligations: In conjunction with the Company's divestiture of its generating business, the Company accrued obligations related to certain purchased power contracts. The Company makes fixed monthly payments to the suppliers or it has made lump sum payments to effectively terminate a number of purchase power contracts. These payments are recorded as regulatory assets and are amortized as they are recovered from customers.

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.

Yankee nuclear decommissioning costs: This regulatory asset represents the estimated future decommissioning billings from a group of three nuclear generating utilities (See Note C "Commitments and Contingencies"). Under settlement agreements, the Company is permitted to recover prudently incurred decommissioning costs through CTCs.

Pension and Postretirement Benefit Plans: Costs of the Company's pension and postretirement benefits plans over amounts reflected in rates are deferred to 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 SFAS No. 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" liability. As the Company has recovery on pension liability on a dollar for dollar basis, it is reasonable that the Company's regulatory assets for pension expenses will be equal to the SFAS No. 158 liability on the balance sheet. Therefore, there will be no impact on the income statement as the revenues per recovery will match the underlying pension and other postretirement benefit expenses.

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.

Regulatory Developments

Granite State
On July 12, 2007, the NHPUC approved a settlement agreement between Granite State, the Staff of the NHPUC and the New Hampshire Office of Consumer Advocate. Among other things, the 2007 Settlement provided for a $2.2 million reduction in Granite State's distribution rates in two steps: the first $1.1 million reduction became effective August 11, 2007 and the second $1.1 million reduction became effective January 1, 2008. The 2007 Settlement also contains a distribution rate plan spanning 5 years effective January 1, 2008 (Rate Plan). During the Rate Plan, distribution rates are frozen except for rate adjustments in the event of certain uncontrollable exogenous events and moderate annual rate adjustments related to specific Reliability Enhancement and Vegetation Management Plans (REP/VMP). The Rate Plan also includes an earnings sharing mechanism based on an imputed capital structure of 50% debt and 50% equity and a return on equity (ROE) of 11%. Earnings above 11% ROE are shared equally between customers and Granite State. The Rate Plan also establishes a storm contingency fund and customer service commitments. On June 27, 2008 the NHPUC approved Granite State's first annual REP/VMP rate adjustment of $0.2 million effective July 1, 2008.

Mass Electric and Nantucket Electric
Rates for services rendered by Mass Electric are the same as for Nantucket Electric. In March 2000, the MADPU approved a long-term rate plan for Mass Electric and Nantucket 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, based upon the movement of a distribution index rate (in cents per kilowatt-hour) of similarly unbundled distribution utilities in New England, New York, Pennsylvania and New Jersey. Mass Electric and Nantucket Electric implemented increases in distribution rates pursuant to this mechanism of 1.59%, 1.90% and 1.54% effective March 1, 2007, 2008, and 2009, respectively. The rate plan also has included provisions for recovery of major storm costs and recovery or passback to customers for exogenous events.

On May 15, 2009, Mass Electric and Nantucket Electric jointly filed a base rate case, which they anticipate the MADPU will act upon for rates effective January 1, 2010. This rate case filing seeks approval of an increase in distribution revenue of approximately $111.3 million. Approximately $30.1 million of this amount relates to storm cost recovery. The filing proposes to continue to include an allowance in rates to replenish the storm fund balance to address future storms. As required by the MADPU, the filing includes a rate decoupling proposal. The filing also includes proposals for the reconciliation of commodity-related bad debt and pension costs. In addition, the filing includes new proposals for other fully reconciling adjustments for other expenses, including capital additions. Mass Electric and Nantucket Electric cannot predict the outcome of this proceeding as hearings and replied briefs are still in process.

Mass Electric had a service quality plan in place in 2006 that provided for penalties and incentives for various service quality metrics, including without limitation, the frequency and duration of outages. In 2006, Mass Electric did not meet the frequency and duration metrics. These results included outages during four severe weather events during 2006. Mass Electric petitioned the MADPU for permission to exclude these four storms from its reliability metrics, based on a provision in a MADPU order (August 17, 2000 order in D.T.E. 99-84 at 51) allowing utilities to make a filing to seek relief from the imposition of service quality penalties where Mass Electric believes that the imposition of a penalty is not warranted from the specific facts of the situation. The MADPU issued an order on June 26, 2009 rejecting the request to exclude the four storms. As a result, Mass Electric's service quality penalty for 2006 is approximately $8 million which is reflected in the regulatory liabilities at March 31, 2009.

Mass Electric and Nantucket Electric provide energy efficiency initiatives for its customers under a single combined program under the jurisdiction of the MADPU and the Massachusetts Department of Energy Resources. The combined approved budget for calendar year 2008 is $61.9 million, and an approved budget for calendar year 2009 is $85.3 million. Mass Electric and Nantucket Electric obtain cost recovery through each company's systems benefit charge. In addition, Mass Electric and Nantucket Electric can earn performance incentives depending on whether certain set goals are met, and are also entitled to seek recovery of lost base revenues, that is, revenues reduced as a result of installed energy efficiency measures. Lost base revenues may be recovered from a set point in time until the companies revenue decoupling proposal is approved by the MADPU.

On May 13, 2009, Mass Electric petitioned MADPU for approval to issue, from time to time, long term debt securities in an amount not to exceed $1.075 billion. The Company cannot predict the outcome of these proceedings.

Narragansett Electric

In September 2004, the RIPUC approved a rate plan that reduced annual distribution rates effective November 1, 2004 by $10.2 million and froze them at that level through 2009. On June 1, 2009, Narragansett filed for an increase in base distribution rates, which Narragansett anticipates the RIPUC will act upon for rates effective March 1, 2010. This rate case filing seeks approval of an increase in distribution revenue of approximately $75.3 million. The filing includes a rate decoupling proposal, along with proposals for the reconciliation of commodity-related bad debt and pension costs. In addition, the filing includes new proposals for other fully reconciling adjustments for other expenses, including capital additions. Narragansett cannot predict the outcome of this proceeding.

On September 17, 2008, Narragansett, NEP, and Northeast Utilities jointly filed with FERC to recover financial incentives for the New England East-West Solution (NEEWS), pursuant to FERC's Transmission Pricing Policy Order, Order No. 679. NEEWS, estimated to cost a total of $2.1 billion, consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address a number of reliability problems in the tri-state area of Connecticut, Massachusetts, and Rhode Island.

Narragansett's share of the NEEWS-related transmission investment is estimated to be $474 million and NEP's share is estimated to be $160 million. Narragansett is fully reimbursed for its transmission revenue requirements on monthly basis by NEP through NEP's Integrated Facilities Agreement. 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 (CWIP) in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Parties opposing the NEEWS incentive have sought rehearing of the FERC order.

Under Rhode Island law, Narragansett is allowed to recover all of its costs for commodity service. Commodity service for customers not taking supply from a competitive supplier is referred to as Standard Offer Service (SOS). In addition, there is a related service called Last Resort Service, which has been provided to customers who left Standard Offer Service to obtain supply from a competitive supplier and then returned to Narragansett for commodity service. Standard offer Service has been supplied pursuant to several long term contracts that expire at the end of 2009. Last Resort Service is provided under short term (less than one year) contracts. In addition, Narragansett is obligated to meet renewable energy standards for all supply. This can be met by the purchase of renewable energy certificates. On April 29, 2009, Narragansett filed its proposed Standard Offer Procurement Plan and its Renewable energy Standards (RES) Procurement Plan, proposing plans for the acquisition of Standard Offer Service beginning January 1, 2010, following the expiration of the existing long term contracts. Narragansett's plans include consideration of entering into long-term contracts for renewable energy resources, which was directed by the Commission on March 31, 2009.

Narragansett continues to be authorized to recover all costs associated with procuring power for its customers, all transmission costs, and costs charged by certain NGUSA affiliates, for stranded costs associated with Narragansett's former electric generation investments.

In August 2006, Narragansett completed the acquisition of the Rhode Island gas assets of Southern Union Company. Pursuant to the Order approving the acquisition, Narragansett agreed to honor the provisions of a May 2002 rate settlement and committed to file a new rate plan within one year of the acquisition date. In November 2008, the RIPUC approved a $13.6 million gas distribution rate increase. The rate increase includes a new rate for low-income customers and increased recovery of commodity related bad debt expense. The RIPUC also approved a 10.5% allowed ROE based on an imputed equity ratio of 47.7%, a discrete funding mechanism for an accelerated base-steel and cast-iron mains replacement program, and a full reconciliation of pension and postretirement benefits other than pensions. The RIPUC approved the proposed rate base, which was bare on forecasted additions to plant in service through the end of the rate year, subject to subsequent adjustments to reflect any actual lower amount of plant in service. The RIPUC denied Narragansett's revenue decoupling proposal, indicating that full revenue decoupling was not appropriate at this time.

On June 18, 2009, Narragansett petitioned the RIPUC for approval to issue, from time to time, long term debt securities in an amount not to exceed $840 million. The Company cannot predict the outcome of these proceedings.

New England Power

New England Regional Transmission Organization (RTO) and Rate Filing: NEP is a participating transmission owner (PTO) in the 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.

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

NEP and the 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 NEP. In this order, FERC overturned the Administrative Law Judge 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 NEP'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 NEP'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 for new transmission investment approved under the regional system planning process 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 pursuant to the Commission's Order No. 679 Transmission Pricing Policy.

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 NEP, filed their brief with the Court on March 23, 2009. The filing of the briefs was completed in May 2009. Oral arguments have not yet been scheduled.

Niagara Mohawk

Third CTC reset and Deferral Account filings: The biannual deferral account filing included in the third CTC reset was made on August 1, 2007 for deferral balances as of June 30, 2007 and projected deferrals through December 31, 2009. Any differences in the final deferral from balances authorized to be reflected in rates and the approved recovery level would be reflected in the next CTC reset filing and resulting rates to customers that take effect after 2009. A NYPSC order establishing the amount of deferral account recovery that will be reflected in the rates during 2008-2009 was approved on December 17, 2007 at $124 million per calendar year. This represents a reduction in rates charged to customers of $76 million per year from the $200 million per year previously being collected under rates approved in the second CTC reset proceeding.

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 by National Grid plc of KeySpan. 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 Merger Rate Plan (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 the 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 has also issued a notice on June 25, 2008 seeking additional comment on 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 Department of Public Service Staff's (Staff) position with respect to these two issues that would result in Niagara Mohawk crediting an additional $35 million of synergy savings to electric and gas customers. Niagara Mohawk disagrees with the Staff's position and on August 4, 2008 filed comments in response. On May 26, 2009, a settlement conference was held with the Staff and other parties to discuss negotiations. The settlement conference ended without an agreement. Niagara Mohawk expects the NYPSC's decision on this matter to be made by the end of the calendar year 2009.

Service Quality Penalties: In connection with its MRP and Gas Rate Plan Joint Proposal (see below), Niagara Mohawk is subject to maintaining certain service quality standards. Service quality measures focus on eleven categories including 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 Low-Income Customer Assistance Program. If a prescribed standard is not satisfied, Niagara Mohawk may incur a penalty, with the penalty amount applied as a credit or refund to customers.

The MRP includes provisions related to frequency and duration of outages that causes the annual $4.4 million penalty associated with these standards to be doubled under certain circumstances when penalties have been incurred in the current year and two of the last four years. In calendar year 2006, Niagara Mohawk incurred a $4.4 million penalty related to outage frequency, which it recorded in fiscal year 2007. Similar penalties were incurred in the two prior years. Based on this performance and consistent with the terms of the MRP, the NYPSC on November 7, 2007 doubled the 2006 penalty associated with outage frequency to $8.8 million per year. In September 2007, the NYPSC also modified the MRP, in the context of the KeySpan merger proceeding, to add an additional incremental $4.4 million penalty exposure for each consecutive year Niagara Mohawk misses the target for a doubled penalty. This additional incremental penalty exposure resulted in a $13.2 million penalty for missing the outage frequency target for 2007. For the twelve months ended March 31, 2008, Niagara Mohawk recorded service quality penalties of $14.2 million. In addition, the Gas Rate Plan Joint Proposal for Niagara Mohawk's gas rates provides for higher negative revenue adjustments in connection with certain service quality performance measures. For the twelve months ended March 31, 2009, Niagara Mohawk has recorded service quality penalty expenses of approximately $0.5 million.

Asset Condition and Capital Investment Plan: On October 22, 2007, Niagara Mohawk filed with the NYPSC reports on its asset condition and capital investment plan for its electric transmission and distribution system. Niagara Mohawk's plan involves 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 regarding the asset condition and capital investment plan. The NYPSC affirmed Niagara Mohawk's need to invest a minimum of $1.4 billion during this five year period and stated that further projects and investments "appear to be justified" from our $2.3 billion plan with the possibility of further expansion over time.

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 Acquisition, the NYPSC had found that the rate impacts associated with certain incremental investments during the remaining period of the MRP would be limited to 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 NGUSA's investment program constituted a major program. Thus, investment could "conceptually" be considered incremental to the rate plan and therefore eligible for deferral recovery. The NYPSC ordered adoption of a previous recommendation made by the Staff finding that such expenditures qualify for deferral under the 2001 MRP. However, the NYPSC also agreed with the Staff that the petition was premature and ordered Niagara Mohawk to supplement its petition with actual expense information once results for calendar year 2008 become 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 merger joint proposal 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 the Niagara Mohawk has been working with the NYPSC to develop. Niagara Mohawk has filed for authority to defer 2008 actual capital expenditures in April 2009. Niagara Mohawk plans to request deferral recovery of 50% of the annual revenue requirement associated with certain capital investments and associated operating expenses after each calendar year through the end of 2011 as allowed by the NYPSC order.

Financial Protections: Niagara Mohawk made a filing on November 19, 2007 proposing certain financial protections for Niagara Mohawk as required by the NYPSC in the order approving the KeySpan Acquisition and made an additional filing with the NYPSC regarding these protections. The NYPSC adopted the protections in March 2008 which provide, among other things, for restrictions on the payment of common dividends if certain credit ratings are not maintained by Niagara Mohawk or National Grid plc; credits to Niagara Mohawk's deferral account of any incremental increase in interest expense due to a decline in Niagara Mohawk's bond rating; a prohibition with respect to certain types of cross-default provisions; and the implementation of a class of preferred stock having one share (the Golden Share), subordinate to any existing preferred stock, the holder of which would have voting rights that limit Niagara Mohawk's right to commence any voluntary bankruptcy, liquidation, receivership or similar proceeding without the consent of the holder of such share of stock. Niagara Mohawk has committed to seek authority from the NYPSC to establish the Golden Share within six weeks of the NYPSC's approval of the petition of certain subsidiaries of KeySpan for the establishment of their respective Golden Shares as required by the NYPSC.

Gas Rate Plan Joint Proposal: Niagara Mohawk filed with the NYPSC on May 23, 2008 for a $95 million rate increase in natural gas delivery rates. Niagara Mohawk had not had a gas delivery rate increase since 1996. The filing included a revenue decoupling proposal, a gas marketing program, a new rate for low-income customers and expanded capital infrastructure investments. The proposed $95 million rate increase included recovery of $11 million of costs associated with an energy efficiency program. Subsequently, the NYPSC transferred the review of the energy efficiency program proposal and the associated cost recovery to a separate proceeding. The filing further reflected an 11% return on equity and a 50% debt and 50% equity capital structure.

On October 27, 2008, the NYPSC Staff recommended that the increase be reduced to $35 million based in part on allowances of 9.68% for return on equity and 41.7% for the equity ratio. In submitting its rebuttal on November 17, 2008, Niagara Mohawk accepted certain of the Staff's adjustments which when combined with other updated information, reduced Niagara Mohawk's requested rate relief to $72 million. Evidentiary hearings concluded in December 2008, after which Niagara Mohawk, Staff and other parties engaged in settlement discussions. On February 13, 2009, a joint proposal reflecting a settlement of the rate filing among Niagara Mohawk, Staff, the U.S. Department of Defense, a large customer group and a group of energy marketers was filed with the NYPSC. The joint proposal 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 post-retirement benefit plans other than pensions and environmental site investigation and remediation costs. Among other deferral mechanisms, the joint proposal permits Niagara Mohawk to true up to the actual cost of new long-term debt, which will protect Niagara Mohawk from the volatility of financial markets and assure that customers pay no more than the actual cost of long-term debt. 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, increased 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 Joint Proposal was approved as is by the NYPSC session and an Order was issued on May 15, 2009 and the new rates went into effect on May 20, 2009. The Order also authorized Niagara Mohawk to implement a surcharge so that it could begin recovering the Temporary State Energy and Utility Service Conservation Assessment on May 20, 2009.

Transmission Rate Case: In February 2008, Niagara Mohawk filed with FERC a formula transmission rate for customers that take service under the New York Independent System Operator (NYISO) tariff. The formula was projected to increase revenues by $9.6 million, or 72% of 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, if accepted by the NYPSC, would resolve all issues in the proceeding. The formula is projected to increase annual revenue by approximately $7.9 million. The settlement provides for an authorized return on equity of 11.5%, including any incentive return. The proposed effective date for the settlement is January 30, 2009 with a phase in of the settlement rate over the period from 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, which would be charged to wholesale transmission customers, will be credited back to retail electric distribution customers through the Transmission Revenue Adjustment Clause (TRAC) mechanism.

Brooklyn Union

Brooklyn Union is currently subject to a five year rate plan through December 2012. The rate plan arose from the rate filing made in the context of the National Grid merger proceeding. Base delivery rates were increased $5 million annually in rate years one through rate year five. However, the increase in base delivery rates will be deferred and used to offset future increases in environmental investigation and remediation costs. The plan is based on an allowed return on equity of 9.6%. Cumulative annual earnings above 10.6% (including a 10 basis point incentive for meeting energy efficiency targets to be established) 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, special franchise taxes and site investigation and remediation costs. In the case of non growth-related capital, Brooklyn Union must return unspent funds below established targets to customers, but may not recover overspending. 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 terms of the rate plans.

KeySpan Gas East

KeySpan Gas East is currently subject to a five year rate plan through December 2012. The rate plan arose from the rate filing made in the context of the National Grid merger proceeding. Base delivery rates were increased by $60 million for on January 1, 2008. In rate years two through five, base delivery rates will be increased by $10 million. However, the increase in delivery rates in years two through five will be deferred and used to offset future increases in environmental investigation and remediation costs. The plan is based on an allowed return on equity of 9.6%. Cumulative annual earnings above 10.6% (including a 10 basis point incentive for meeting energy efficiency targets to be established) 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, KeySpan Gas East must return unspent funds below established targets to customers, but may not recover overspending. KeySpan Gas East 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 terms of the rate plans.

Boston Gas

Boston Gas currently has a long term rate plan in place to 2013, unless terminated earlier, Boston Gas has notified the MADPU of its intent to file a base rate case in 2010. Under the long term rate plan, rates are adjusted each year with the approval of the MADPU based on a GDP-based price cap formula. On November 1, 2008, the MADPU approved a base rate increase of $6.5 million under the rate plan. In addition, an increase of $26.0 million in the local distribution adjustment clause was approved to recover pension and other postretirement costs. The MADPU also approved 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 are weighted-average cost of capital. There is also an earnings sharing mechanism. If the return on equity (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 November 17, 2008, the Boston Gas, Colonial Gas and Essex Gas filed a combined request for approval of a three year gas portfolio optimization agreement with ConocoPhillips. An order was issued on April 1, 2009 approving the agreement, including proposed margin sharing, but limiting the term to a period of one year. Under the terms of the confidential agreement, customers will receive a minimum guaranteed payment plus a share of any revenues generated above the guarantee amount.

Colonial Gas
Colonial Gas is subject to a MADPU imposed 10 year rate freeze that will expire in September 2009. Current rates will remain in effect unless and until a change in base rates is requested and approved by the MADPU. Colonial has notified the MADPU of its intent to file a base rate case in 2010.

EnergyNorth
On February 23, 2008, EnergyNorth, filed for a $10 million rate increase in natural gas delivery rates with the NHPUC. This filing represents the first delivery rate increase since 1992 and reflected an 11.5% return on equity and a 50/50 debt to equity capital structure. The filing enabled temporary gas delivery rates to go into effect, subject to refund, in late August 2008, with the final approved gas delivery rate increase expected in February 2009. In May 2009, the NHPUC approved a partial settlement reached between EnergyNorth, the Staff of the NHPUC, and other parties that resolved all issues related to the case except for the determination of the allowed return on equity. The Commission also ordered that the allowed ROE be 9.54%. The result of the Commission Order is an increase in gas distribution rates of $5.5 million. On June 29, 2009, EnergyNorth filed a motion for reconsideration of the Commissions determination of an allowed ROE of 9.54%. The NHPUC has not issued an order in response to the motion.

Temporary State Assessment Pursuant to PSL Section 18-a(6): In June 2009, Niagara Mohawk, KeySpan Gas East, and Brooklyn Union made a compliance filing with the NYPSC regarding the implementation of the Temporary State Energy & Utility Conservation Assessment per §18-a(6) of the New York Public Service Laws of 2009. The combined General & Temporary Conservation assessment will equal two percent of the prior calendar year's gross operating revenues derived from intra-state utility operations, including ESCO revenues. Per Order dated June 19, 2009, the NYPSC authorized recovery of the revenues required for payment of the Temporary State Assessment, including carrying charges, subject to reconciliation over five years, July 1, 2009 through June 30, 2014. In its initial compliance filing, the Company calculated the incremental assessment to be collected from customers, including carrying charges and an allowance for uncollectible amounts, to be approximately $100 million for the period from July 1, 2009 through June 30, 2010. On July 1, 2009 the Company filed an alternative proposal, whereas the Company would recover the incremental assessment over a fiscal year basis, with a compressed first-year period from May 20, 2009 through March 31, 2010. An Order in regards to both the compliance and alternative filings is outstanding.

Green Communities Act
On July 2, 2008, the Commonwealth of Massachusetts enacted into law comprehensive legislation regarding energy policy and the environment. Entitled the Green Communities Act, this legislation is broad, mandating large scale and innovative ideas for implementing renewable

energy, alternative energy, and energy efficiency throughout the Commonwealth. The legislation sets forth numerous requirements for gas and electric utilities. Provisions of the law that will affect Mass Electric, Nantucket Electric, Boston Gas and Colonial Gas include requirements to invest in demand side resources that are cost-effective or less expensive than current energy supply costs, long-term contracts with renewable electricity suppliers for up to 3% of the utilities' load, the development of a smart grid pilot program, and net metering to allow customers to sell self-generated electricity back to the utilities. Utilities would be allowed to recover costs associated with these new requirements and have the opportunity to earn incentives for certain of these provisions. The law allows electric utilities to invest in solar generation, provided, however, that such company shall not own or operate more than 25 megawatts (MW) before January 1, 2009 and 50 MW after January 1, 2010. Pursuant to this provision, on April 23, 2009, Mass Electric and Nantucket Electric filed a proposal with the MADPU to construct, own, and operate approximately 5 MW of solar generation at a total capital cost of approximately $31 million. In addition, under the new law, the maximum level of service quality penalties has been increased from 2.0 to 2.5% of distribution revenues. Any future holding company mergers will now require approval of the MADPU. Mass Electric and Nantucket Electric also filed a proposed smart grid pilot program on April 1, 2009 which is also pending at the MADPU. The overall cost of the proposed pilot program is estimated at approximately $56.4 million and is subject to MADPU approval. If the program is approved, the provisions of the Green Communities Act allow for the recovery of the program costs through commodity service rates. Mass Electric and Nantucket Electric also plan to file with the MADPU for a second phase of the smart program in September 2009.

Oversight Investigation
On April 6, 2007, the Attorney General filed a petition to request that the MADPU open an oversight investigation to examine the impact of the merger of National Grid plc and KeySpan on Massachusetts customers. Hearings on the Attorney General's request were held on five separate dates in February and March of 2009. On May 15, 2009, the Attorney general submitted it's brief. The brief focused primarily on the service quality impacts of the merger. Mass Electric, Nantucket Electric, Boston Gas and Colonial Gas filed briefs on June 8, 2009. Reply briefs have been filed and the Company cannot predict the outcome of these proceedings.

NOTE C – 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 located within a Clean Air Act (CAA) ozone non-attainment and PM 2.5 (fine particulate matter) non-attainment area, and are likely to be subject to increasingly stringent NOx, SO2 and particulate emission limitations. While regulatory programs to

implement such limitations are the subject of various federal legal proceedings, the Company is implementing strategies to achieve various improvements. These improvements also include measures to improve fuel efficiency and reduce CO2 emissions and are planned to be incurred over a five to six year period and are estimated to cost approximately $100 million. Such amounts are substantially recoverable through contractual provisions with LIPA.

Water:
Additional capital expenditures associated with the compliance and renewal of the surface water discharge permits for our power plants will likely be required by the Department of Environmental Conservation (DEC). Such amounts, estimated to be approximately between $60 million and $ 90 million over the next ten years, are recoverable through contractual provisions with 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 England and New York. 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 using an appropriate fair value methodology. Adjustments to the environmental reserves based on changing circumstances will be undiscounted. Environmental reserves recorded prior to the KeySpan Acquisition for non-KeySpan companies have not been discounted.

At March 31, 2009, 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, 2009 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, MADPU, 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 $1.7 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 $25.8 million, which amount has been accrued 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

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company (Yankee Atomic), Connecticut Yankee Atomic Power Company (Connecticut Yankee), and Maine Yankee Atomic Power Company (Maine Yankee) (together, the Yankees). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units 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.

The three units are as follows:

	The Company's Investment as of March 31, 2009			Future Estimated Billings to the Company
Unit	Percent	(in millions of dollars)	Date Retired	(in millions of dollars)
Yankee Atomic	34.5	$ 0.6	Feb 1992	$ 23.3
Connecticut Yankee	19.5	$ 2.5	Dec 1996	$ 59.5
Maine Yankee	24	$ 0.6	Aug 1997	$ 12.9

With respect to each of the units, at March 31, 2009 NEP has a $167 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 NEP. NEP's share of the decommissioning costs is accounted for in purchased electric energy on the income statement. Under settlement agreements, NEP is permitted to recover prudently incurred decommissioning costs through contract termination charges.

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 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 6, 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 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 has remanded the matter to the trial court for further proceedings and a discovery schedule leading to an August 2009 trial date has been entered. 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. On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2001 and 2002. DOE does not anticipate having a long term storage facility available to accommodate spent fuel for at least a decade. The decommissioning costs that are actually incurred by the Yankees may exceed the estimated amounts, perhaps substantially.

Connecticut Yankee Rate Filing, Prudence Challenge and Other Proceedings

On July 1, 2004, Connecticut Yankee asked FERC for a rate increase to reflect increased costs for decommissioning, pensions and other employment benefits, increased security and insurance costs and other expenses. In aggregate, the increase requested amounted to approximately $396 million through 2010. NEP's share is included in the future estimated billings shown in the preceding table. On November 16, 2006, FERC issued an Order approving a settlement reached by parties to the proceeding. Under the settlement, as a result of the operation of a budget incentive mechanism established in a prior rate settlement, NEP was not allowed to recover $1 million of its expenditures.

The settlement provides that Connecticut Yankee may resume payment of dividends to return equity to sponsors. After January 1, 2008, Connecticut Yankee will not be allowed to earn a return on equity greater than $10 million.

On July 31, 2008, Connecticut Yankee submitted an application to FERC to reduce its rates by $0.6 million annually. This reduction is the net effect of: (i) a reduction of $2.5 million annually in decommissioning charges, as a result of the reconciliation of actual and projected costs of completing decommissioning and (ii) an increase of $1.9 million annually in the recovery of costs for post-employment benefits other than pension. On September 10, 2008 FERC issued an order accepting this rate filing and settlement.

Maine Yankee Rate Filing

Maine Yankee submitted a Section 205 rate filing to FERC on August 1, 2008. The sole purpose of this filing was to modify the Maine Yankee tariff in order to replenish the Spent Fuel Disposal Trust (SFDT) Fund as contemplated in the settlement agreement approved by the Commission in Maine Yankee's last rate case proceeding, on September 16, 2004. Maine Yankee is proposing a five-year recovery period and requests $6.4 million on an annualized basis to fund the SFDT. Because the effective date of this filing occurs on the month following the completion of decommissioning collections, Maine Yankee's annual decommissioning rates will reduce to zero and therefore, even with the recovery of the amounts to replenish the SFDT fund, its total rates will decrease by approximately $20 million annually.

In its initial FERC filing, Maine Yankee requested a 6.5% ROE. In its intervention and comments, the Maine Public Utility Commission (PUC) indicated that they could not support the 6.5%. After negotiations, the parties agreed to a 5.5% ROE and the filing was amended to include this change. On October 30, 2008, FERC accepted Maine Yankee's amended filing, effective as of November 1, 2008.

Nuclear Contingencies

As of March 31, 2009 and 2008, the Company has a liability of $167 million and $165 million, respectively, in non-current liabilities for the disposal of nuclear fuel irradiated prior to 1983 at Niagara Mohawk's former nuclear facilities. In January 1983, the Nuclear Waste Policy Act of 1982 (the Nuclear Waste Act) established a cost of $.001 per kWh of net generation for current disposal of nuclear fuel and provides for a determination of the Company's 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 Energy Group Inc., which purchased the 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 slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010.

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, as of March 31, 2009, are summarized in the table below.

Fiscal Years Ended March 31,	Estimated Payments (in millions of dollars)	
2010	$	256.6
2011	$	183.7
2012	$	154.7
2013	$	61.8
2014	$	62.8
Thereafter	$	182.8

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, 2009.

Fiscal Years Ended March 31,	Estimated Payments (in millions of dollars)	
2010	1,165.8	
2011	$	988.2
2012	$	736.8
2013	$	529.8
2014	$	482.3
Thereafter	$	432.1

Legal Matters

Narragansett Electric
The Company has been in litigation with Constellation Energy Commodities Group (Constellation) in two cases. In the first case, commenced on September 11, 2006 in the U.S. District Court for the District of Rhode Island, Constellation had alleged that certain power purchase agreements entitled it to additional compensation for capacity during calendar years 2006-2009, following the FERC approved settlement in the forward capacity market. According to Constellation, the resolution of this claim could have adversely affected Constellation in amounts upwards of $150 million. In the second case commenced on April 14, 2008 in the U.S. District Court for the District of Massachusetts, Constellation had alleged that certain power purchase agreements entitled it to payments for a fuel adjustment factor during calendar years 2005-2009. The prospective portion of the fuel adjustment claim was subject to the effects of changing fuel prices. By Constellation's methodology for payment calculation, it was estimated that damages could have exceeded $200 million.

On September 30, 2008, the RIPUC voted to approve a settlement of both matters that had been signed by the Company, the Division of Public Utilities and Carriers (represented by the Rhode Island Attorney General's Office), and Constellation. Under the settlement, the Company made a lump sum payment of $20 million, payable within 20 days of the written order becoming final and non-appealable. In addition, the pricing provisions of two of the power purchase agreements have been amended to provide for monthly contract reservation charges paid in calendar year 2009, totaling $2.5 million per month, and payable on the last day of the month, from January 31, 2009 through December 31, 2009. The monthly contract reservation charges are not tied to volume, but are contingent upon Constellation's performance under the contracts. On October 21, 2008, the RIPUC issued its final written order, confirming approval of the settlement, and on December 23, 2008, the RIPUC approved the Company's revised commodity service rates, which include recovery of the settlement costs and went into effect in January 2009. The approvals of the RIPUC allowed the Company recovery of the lump sum payment and contract reservation charges from customers in Narragansett's commodity service rates the next time Narragansett changes those rates, which is expected to occur as of January 1, 2009. On October 21, 2008, the RIPUC issued its final written order, confirming approval of the settlement.

The Company accrued the $20 million settlement on its March 2008 balance sheet. Since the payment is fully recoverable from the Company's ratepayers. We recorded an offsetting customer accounts receivable in a like amount resulting in no impact to the Company's statement of Income.

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

On 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 NEP'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. NEP appealed this interest ruling to the First Circuit on the ground 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 MADPU'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.

In 1998, NEP filed a collection action in Massachusetts Superior Court (Worcester County) to collect the CTC from Norwood. In June 2004, NEP obtained a judgment from the Superior Court based on amounts owed through January 31, 2001. The Massachusetts appellate courts sustained NEP's judgment against several challenges by Norwood. State court proceedings have been stayed pending the outcome of the FERC and First Circuit proceedings described above.

To date, Norwood has paid NEP $93.4 million including its last payment of approximately $53.2 million made in January 2008. On July 2, 2009, NEP and Norwood filed a settlement agreement at FERC that provides for Norwood to make an additional payment of $20 million by no later than August 31, 2009, following FERC acceptance of the settlement. FERC approved the settlement and Norwood paid the final $20 million payment in August 2009.

Brooklyn Union Gas Company and KeySpan Gas East Corporation
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. The Company has been conducting site investigations and remediations at these locations pursuant to Administrative Orders on Consent (ACO) with the New York State DEC. One of these lawsuits was settled on May 15, 2008 by purchasing a residential property. There is one lawsuit pending related to the former Clifton manufactured gas plant on Staten Island. The Company intends to contest each of the remaining 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 the Company 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 and/or the Company 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. The Company has entered into an ACO for one of the land-based sites and is currently negotiating the terms of another ACO for the remaining land-based sites. To resolve issues associated with the waterway, The Company and the four other companies are currently negotiating the terms of a Consent Decree. 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.

Other

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 the 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. In April 2008, KeySpan received a second CID in connection with this matter and in July 2009, the Department of Justice made and initial settlement offer to KeySpan. We continue to believe that our activity in the capacity market is consistent with all applicable laws and regulations and will continue to fully cooperate with this investigation.

Lease Obligations

The Company has various operating leases which include the lease of the Company's Brooklyn headquarters, a leveraged lease financing arrangement (as discussed below), as well as leases for other buildings, office equipment, vehicles and power operating equipment. Future minimum cash lease payments under various leases are $137.3 million per year over the next five years and $719.7 million, in the aggregate, for all years thereafter.

The Company entered into a lease dated January 7, 2008, in connection with an office building newly constructed in Waltham, Massachusetts. The term of the lease expires twenty years and five months after the Commencement Date. The base rent under the lease increases every five years and will range between $10 million and $13 million annually. The building, including all significant tenant improvements, was completed on May 18, 2009 – the Commencement Date.

Sale/leaseback Transaction: The Company had a leveraged lease financing arrangement associated with the Ravenswood Expansion. In May 2004, the unit was acquired by a lessor from our subsidiary, KeySpan Ravenswood, LLC, and simultaneously leased back to that subsidiary. All the obligations of KeySpan Ravenswood, LLC have been unconditionally guaranteed by us.

This lease transaction qualified as an operating lease under SFAS 98 "Accounting for Leases: Sale/Leaseback Transactions Involving Real Estate; Sales-Type Leases of Real Estate; Definition of the Lease Term; an Initial Direct Costs of Direct Financing Leases, an amendment of FASB Statements No.13, 66, 91 and a rescission of FASB Statement No. 26 and Technical Bulletin No. 79-11." The sale of KeySpan Ravenswood LLC provided for the restructuring and transfer of KeySpan's interest in the Ravenswood Expansion. TransCanada Corporation, the buyer of KeySpan Ravenswood LLC, prepaid this sublease and provided back-to-back guarantees. However, the original lease will remain in place and we will continue to make the required payments under such lease through 2039. At March 31, 2009, the Company's obligation related to the Sale/leaseback transaction was $528.7 million.

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt as discussed in Note H, "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, 2009, 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 of Exposure	Expiration Dates
Guarantees for Subsidiaries				
Medium-Term Notes - KeySpan Gas East Corporation	(i)	$	400.0	2010
Industrial Development Revenue Bonds	(ii)		128.3	2027
Ravenswood - Sale/leaseback	(iii)		619.2	2040
Reservoir Woods	(iv)		303.6	2029
Surety Bonds	(v)		77.6	Revolving
Commodity Guarantees and Other	(vi)		76.1	2009-2027
Letters of Credit	(vii)		137.5	2009-2011
		$	1,742.3	

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

(i) The Company has fully and unconditionally guaranteed $400 million to holders of Medium-Term Notes issued by KeySpan Gas East. These notes are due to be repaid February 1, 2010. KeySpan Gas East is required to comply with certain financial covenants under the debt agreements. The face value of these notes is included in current portion of the long-term debt on the Consolidated Balance Sheet.

(ii) 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 are included in long-term debt on the Consolidated Balance Sheet.

(iii) The Company had guaranteed all payment and performance obligations of KeySpan

Ravenswood, LLC, the lessee under the sale/leaseback transaction associated with the Ravenswood Expansion, including future decommissioning costs prior to the sale. The cash consideration for KeySpan Ravenswood, LLC included prepayment from TransCanada for the remaining lease payments on a net present value basis. The Company's requirement to make regular lease payments under this lease continues after the sale of KeySpan Ravenswood, LLC.

(iv) The Company has fully and unconditionally guaranteed approximately $303.6 million in lease payments through 2029 related to the lease of office facilities at Reservoir Woods in Waltham, MA.

(v) 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. At March 31, 2009, the total cost to complete such remaining bonded projects is estimated to be approximately $8.3 million.

(vi) 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, 2009.

(vii) 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 or 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 FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."

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, 2009 and 2008 was $67.7 million and $67.6 million, respectively.

NOTE D – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table details the components of accumulated other comprehensive income (loss) for the fiscal years ended March 31, 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, 2007	$ 9.3	$ (410.8)	$ (0.2)	$ (401.7)
Other comprehensive income (loss), net of taxes:				
Unrealized gains (losses) on securities	(13.6)	-	-	(13.6)
Unrealized gains (losses) on hedges	-	-	-	-
Change in pension and other postretirement provisions	-	(100.5)	-	(100.5)
Relassification adjustment for (gain)/ loss included in net income	3.0	-	0.2	3.2
March 31, 2008	$ (1.3)	$ (511.3)	$ -	$ (512.6)
Other comprehensive income (loss), net of taxes:				
Unrealized gains (losses) on investments	(15.4)	-	-	(15.4)
Unrealized gains (losses) on hedging	-	-	2.4	2.4
Change in pension and other postretirement provisions	-	(517.7)	-	(517.7)
Reclassification adjustment for (gain) included in net income	(0.4)	-	-	(0.4)
March 31, 2009	$ (17.1)	$ (1,029.0)	$ 2.4	$ (1,043.7)

NOTE E – DERIVATIVE CONTRACTS AND FAIR VALUE MEASUREMENTS

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 operations. These financial exposures are monitored and managed as an integral part of the Company's overall Financial Risk Management Policy. At the core of the policy is a condition that the Company will engage 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.

As discussed in greater detail below, certain derivative instruments employed by the Company are accounted for as cash-flow hedges and receive hedge accounting treatment under SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," collectively SFAS 133. The change in fair value of instruments that qualify for hedge accounting are deferred in accumulated other comprehensive income and will be reclassified through purchased electricity or purchased gas expense 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 SFAS 71 "Accounting for the Effects of Certain Types of Regulation" 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.

Financial Derivatives – Recorded under SFAS 71

Regulated Utilities – Gas

We use derivative financial instruments (swaps, options, and futures) to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with our gas service territories. Our strategy is to minimize fluctuations in gas sales prices to our regulated firm gas sales customers. The accounting for these derivative instruments is subject to SFAS 71. Therefore, the fair value of these derivatives are 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 sales customers consistent with regulatory requirements. At March 31, 2009 the net fair value of these derivative instruments was a liability of $274.9 million. At March 31, 2008 the net fair value of these derivative instruments was $152.6 million.

Regulated Utilities - Electricity

We also use derivative financial instruments (swaps and futures) to reduce the cash flow variability associated with the purchase price for a portion of future electricity purchases associated with our electric service territories. Our strategy is to minimize fluctuations in electricity sales prices to our regulated firm electric sales customers. The accounting for these derivative instruments is subject to SFAS 71. Therefore, the fair value of these derivatives are 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 electric sales customers consistent with regulatory requirements. At March 31, 2009 the net fair value of these derivative instruments was a liability of $42.5 million. At March 31, 2008 the net fair value of these derivative instruments was $10.3 million.

Physical Derivatives – Recorded under SFAS 71

Regulated Utilities

As a result of a USGen bankruptcy settlement agreement (Bankruptcy Settlement), NEP resumed the performance and payment obligations under power supply contracts that had been transferred to USGen when the Company divested its generating business. The fair value of these derivative instruments at March 31, 2009 was a liability of $174.5 million. The fair value of these derivative instruments at March 31, 2008 was a liability of $94.0 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. In accordance with the Bankruptcy Settlement, the Company received proceeds of approximately $196 million in June 2005 from USGen. That amount relates in part to the power supply contracts and the Company is crediting that amount to customers through a reduction in rates through December 31, 2009.

SFAS 133 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. Certain contracts for the physical purchase of natural gas associated with our regulated gas service territories do not qualify for normal purchases under SFAS 133. These derivatives are also subject to SFAS 71 accounting treatment. At March 31, 2009, the net fair value of these derivatives was a liability of $13.5 million. The fair value of these derivative instruments at March 31, 2008 was $40.3 million.

Financial Derivatives – Receiving Hedge Accounting

Our gas production subsidiary, Seneca-Upshur, utilizes 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, 2009, Seneca-Upshur has hedge positions in place for approximately 70% of its estimated 2009/2010 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 December 2009. The fair value of these derivative instruments at March 31, 2009 was $4.2 million. The amount of gains currently included in accumulated other comprehensive income and expected to be reclassified to earnings in the next twelve months is $4.2 million. Ineffectiveness associated with these outstanding derivative financial instruments was immaterial for the three months ended March 31, 2009. The fair value of these derivative instruments at March 31, 2008 was a liability of $7.0 million.

These derivative financial instruments are designated as cash flow hedges under SFAS 133 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. Hedge ineffectiveness for the twelve months ended March 31, 2009 was immaterial.

Financial Derivatives – Not Receiving Hedge Accounting

Additionally, the Company employs a limited number of unleaded gasoline and diesel swaps to hedge a small portion of its risk associated with changing prices for fleet fuel, 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 maximum length of time over which derivative financial instruments are in-place is through October 2010. The fair value of these contracts at March 31, 2009 was a liability of $0.2 million. We use market quoted forward prices to value these contracts. The fair value of these derivative instruments at March 31, 2008 was $1.3 million.

Treasury financial instruments

Financial derivative 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, 2009, the Company had a net hedged liability position of $10.4 million on $571.9 million of debt. At March 31, 2008, the Company had a net hedged liability position of $14.0

million on $541.5 million of debt. Net losses on the derivative financial instruments were $19.2 million and $0.9 million for the twelve months ended March 31, 2009 and 2008, respectively.

The following are commodity volumes associated with the derivative contracts:

As of March 31, 2009		
('000)		Total
	Gas (dths)	219,558
Physicals	Electric (Mwhs)	4,524
	Gas swaps (dths)	94,457
	Gas options (dths)	1,036
	Gas futures (dths)	29,610
	Electric futures (Mwhs)	18
Financials	Electric swaps (Mwhs)	4,090
	Gas (dths)	**344,661**
Total	**Electric (Mwhs)**	**8,632**

In March 2008, the FASB issued SFAS No. 161 "Disclosure about Derivative Instruments and Hedging", to amend and expand the disclosure requirements of SFAS No. 133 with the intent to provide users of the financial statement with a better understanding of how and why an entity uses derivatives instruments. Accordingly, this statement, SFAS No. 161, requires enhanced disclosures about an entity's derivative and hedging activities and thereby improves the transparency of financial reporting. Effective January 1, 2009, the Company adopted SFAS 161 which has been applied to our financial reports for the period ending March 31, 2009.

The following disclosures reflect the Company's derivative instrument positions for the periods indicated, excluding those elected as normal purchase normal sale):

Fair Values of Derivative Instruments

	Asset Derivatives March 31, 2009	Asset Derivatives March 31, 2008		Liability Derivatives March 31, 2009	Liability Derivatives March 31, 2008
Derivative not designated as hedging instruments under Statement 133	(In Millions of Dollars)			(In Millions of Dollars)	
FAS 71					
Gas Contracts:					
Gas Futures Contract - current asset	3.5	27.5	Gas Futures Contract - current liability	(78.1)	-
IPP Gas Contract - current asset	-	10.7	Gas Swap Contract - current liability	(192.1)	(0.0)
Gas Swap Contract - current asset	14.7	114.0	Gas Options Contract - current liability	(1.4)	(0.2)
Gas Options Contract - current asset	0.1	2.2	Gas Purchase Contract - current liability	(13.1)	(5.2)
Gas Purchase Contract - current asset	27.6	2.0			
Current Asset	*45.9*	*156.3*	*Current Liability*	*(284.6)*	*(5.5)*
Gas Futures Contract - deferred asset	0.0	3.5	Gas Futures Contract - deferred liability	(7.2)	0.0
Gas Swap Contract - deferred asset	0.8	11.6	Gas Swap Contract - deferred liability	(15.3)	(16.6)
Gas Purchase Contract - deferred asset	9.2	103.0	Gas Purchase Contract - deferred liability	(37.3)	(56.4)
Deferred Asset	*10.0*	*118.1*	*Deferred Liability*	*(59.7)*	*(73.0)*
Electric Contracts:					
Electric Futures Contract - Current Asset	-	10.3	Electric Futures Contract	(0.1)	-
			IPP Electric Contract - Current Liability	-	(51.1)
			Electric Swap Contract - Current Liability	(15.5)	-
			Electric Purchase Contract - Current Liability	(29.5)	(19.3)
			Current Liability	*(45.1)*	*(70.4)*
			Electric Swap Contract - Deferred Liability	(26.9)	-
			Electric Purchase Contract - Deferred Liability	(145.0)	(74.9)
Deferred Asset	-	-	*Deferred Liability*	*(172.0)*	*(74.9)*
Subtotal	*55.9*	*284.7*		*(561.4)*	*(223.7)*
Non FAS 71					
Gas Contracts:					
Gas Swap Contract - Current Asset	0.3	1.2	Gas Swap Contract - Current Liability	(0.6)	(0.1)
Gas Purchase Contract - Current Asset	1.1	0.0	Gas Purchase Contract - Deferred Liability	-	(1.1)
Oil Contracts:					
			Oil Swap Contract - Current Liability	(0.9)	(0.3)
Electric Contracts:					
Electric Swap Contract - Current Asset	-	1.6			
Subtotal	*1.4*	*2.8*		*(1.5)*	*(1.5)*
Total derivatives not designated as hedging instruments under Statement 133	57.3	287.5		(562.9)	(225.2)
Derivative designated as hedging instruments under Statement 133					
Cash Flow Hedge					
Gas Contracts:					
Gas Swap Contract - Current Asset	4.2	-	Gas Swap Contract - Current Liability	-	(5.4)
			Gas Swap Contract - Deferred Liability	-	(1.6)
Total derivatives designated as hedging instruments under Statement 133	4.2	-		-	(7.0)
Total Commodity Derivatives	61.5	287.5		(562.9)	(232.2)
Interest Rate and Currency Swap					
Deferred asset	10.1	14.0	Deferred liability	(20.5)	-
Total Derivatives	71.6	301.5		(583.4)	(232.2)

Fair Values of Derivative Instruments - Income Statement

(in millions of dollars)

Derivatives Not Designated as Hedging Instrument under Statement 133	**YTD Movement**	March 31, 2009	March 31, 2008
FAS 71			
Gas Contracts:			
Gas Futures Contract - Regulatory Asset	$ (85.3)	$ (85.3)	$ -
Gas Swap Contract - Regulatory Asset	(190.7)	(207.3)	(16.6)
Gas Option Contract - Regulatory Asset	(1.2)	(1.4)	(0.2)
Gas Purchase Contract - Regulatory Asset	11.3	(50.3)	(61.6)
Gas Futures Contract - Regulatory Liability	(27.5)	3.5	31.0
IPP Gas Contract - Regulatory Liability	(10.7)	-	10.7
Gas Swap Contract - Regulatory Liability	(110.0)	15.5	125.5
Gas Option Contract - Regulatory Liability	(2.1)	0.1	2.2
Gas Purchase Contract - Regulatory Liability	(68.2)	36.8	105.0
Gas Subtotal	**(484.3)**	**(288.4)**	**196.0**
Electric Contracts:			
Electric Futures Contract - Regulatory Asset	(0.1)	(0.1)	-
IPP Electric Contract - Regulatory Asset	51.1	-	(51.1)
Electric Swap Contract - Requlatory Asset	(42.5)	(42.5)	-
Electric Purchase Contract - Regulatory Asset	(80.4)	(174.5)	(94.2)
Electric Futures Contract - Regulatory Liability	(10.3)	0.0	10.3
Electric Subtotal	**(82.1)**	**(217.0)**	**(134.9)**
Subtotal	**$ (566.4)**	**$ (505.4)**	**$ 61.0**
Non FAS 71			
Gas Contracts:			
Gas Swap - Other Income (Deduction)	$ (1.8)	$ (0.5)	$ 1.2
Gas Purchase - Other Income (Deduction)	2.2	1.1	(1.1)
Gas Swap - Other Revenues	0.2	0.1	(0.1)
Gas Subtotal	0.6	0.7	0.1
Oil Contracts:			
Oil Swap - Other Income (Deduction)	(0.6)	(0.9)	(0.3)
Oil Subtotal	(0.6)	(0.9)	(0.3)
Electric Contracts:			
Electric Swap - Fuel and Purchased Power	(1.6)	-	1.6
Electric Subtotal	(1.6)	-	1.6
Subtotal	**(1.5)**	**(0.2)**	**1.3**
Total Commodity Derivatives	**$ (567.9)**	**$ (505.6)**	**$ 62.3**
Interest Rate and Currency Swap			
Other interest expense	$ 19.1	$ (10.4)	$ 14.0

Since SFAS 71 accounting treatment is currently being applied to most derivative financial instruments, movements in the fair value of these instruments are recorded as a regulatory asset or liability, rather than through the income statement.

Fair Values of Derivative Instruments - Cash Flow Hedging
(in millions of dollars)

Derivative in Statement 133 Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recongized in Accumulated Other Comprehensive Income (AOCI) on Derivative (Effective Portion)		Location of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
	March 31, 2009	March 31, 2008		March 31, 2009		March 31, 2009
Seneca Upshur						
Gas Contracts:						
Accumulated Other Comprehensive Income	4.2	(7.0)	Gas Revenue	(1.9)	Other Income (Deductions)	(0.0)
Total	4.2	(7.0)		(1.9)		(0.0)

Certain of NGUSA's derivative instruments contain provisions that require NGUSA's debt to maintain an investment grade credit rating from each of the major credit rating agencies. If NGUSA's credit rating were to fall below a certain level, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on March 31, 2009 is $251.5 million for which NGUSA has posted collateral of $38.7 million. If NGUSA's credit rating were to be downgraded by one notch, it would be required to post $77 million additional collateral. If NGUSA's credit rating were to be downgraded by three notches, it would be required to post $ 194.5 million additional collateral to its counterparties.

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by a counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively managed by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support. In instances where the counterparties' credit quality has declined, or credit exposure exceeds certain levels, we may limit our credit exposure by restricting new transactions with counterparties, requiring additional collateral or credit support and negotiating the early termination of certain agreements. At March 31, 2009, the company has received $3.4 million from, and paid $129.5 million to its counterparties as collateral associated with outstanding derivative contracts.

Fair Value Measurements

Effective April 1, 2008, National Grid adopted, SFAS 157 "Fair Value Measurements", which requires expanded disclosure for assets and liabilities that are recorded on the Consolidated Balance Sheet at fair value. The adoption of SFAS 157 for fair value on a recurring basis has been applied to commodity derivative and available for sale securities valuation. SFAS 157 has been applied prospectively from April 1, 2008, except for limited retrospective application to selected items including financial instruments that were measured at fair value using the transaction price in accordance with the requirements of Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Day one gains and losses previously deferred under EITF Issue No. 02-3 should be recorded as a cumulative effect adjustment to regulatory assets / liabilities at the date of adoption. As of April 1, 2008, KeySpan recorded a non-cash reduction to derivative asset of $ 18.8 million relating to certain long term LNG contracts. Since these contracts are related to our regulated gas distribution operations, the cumulative effect adjustment has been recorded as a regulatory liability. National Grid primarily applies the market and income approach for recurring fair value measurements and valuation techniques to maximize observable inputs. National Grid has elected to defer the adoption of SFAS 157 for nonrecurring fair value measurement disclosures of non-financial assets and liabilities until April 1, 2009.

As defined in SFAS 157, 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. To increase consistency and comparability in fair value measurements, SFAS No. 157 establishes a 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. Derivative assets and liabilities utilizing Level 1 inputs include active exchange-based derivatives (e.g. natural gas futures traded on NYMEX).

- **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. Derivative assets and liabilities utilizing Level 2 inputs include non-exchanged-based financial contracts (e.g. OTC gas financial swap) and standard NAESB physical gas supply contracts.

- **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. Derivative assets and liabilities utilizing Level 3 inputs are mainly customized physical gas contracts, certain financial contracts, as well as some standard physical gas supply contracts and over the counter financial options contracts.

The determination of the fair value incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved but also the impact of National Grid's nonperformance risk on its liabilities.

Derivatives — we enter into a variety of derivative instruments to include both exchange traded and OTC power and gas forwards, options and swaps.

Our level 1 fair value derivative instruments primarily consist of natural gas futures traded on the NYMEX. There is no liquidity or credit reserve associated with such trades, and no discounting as well.

Our level 2 fair value derivative instruments primarily consist of our power and gas OTC swaps as well as NYMEX swaps and forward physical gas deals where market data for pricing inputs is observable. We obtain our level 2 pricing inputs from NYMEX and Platts mark-to-market when it can be verified by available market data from Intercontinental Exchange. Our 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.

Our level 3 fair value derivative instruments primarily consist of our gas OTC forwards, options, and physical gas or power 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. The value is categorized as level 3. 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.

The following table presents assets and liabilities measured and recorded at fair value on the Company's Consolidated Balance Sheet on a recurring basis and their level within the fair value hierarchy at March 31, 2009:

(in millions of dollars) Contracts	Level 1	Level 2	Level 3	Balance at Marh 31, 2009
Available for sale securities:				
Assets	$ 82.6	$ 115.8	$ -	$ 198.4
Commodity derivative instruments:				
Assets	$ -	$ 14.0	$ 47.5	$ 61.5
Liabilities	(81.3)	(248.3)	(233.3)	(562.9)
Total derivative net assets	$ (81.3)	$ (234.3)	$ (185.8)	$ (501.4)
Interest rate and currency swap:				
Assets	$ -	$ 10.1	$ -	$ 10.1
Liabilities	-	(20.5)	-	(20.5)
Total derivative net assets	$ -	$ (10.4)	$ -	$ (10.4)

The following table presents the fair value reconciliation of level 3 assets and liabilities measured at fair value on a recurring basis during the twelve months ended March 31, 2009:

Year to Date Level 3 Movement Table

(in millions of dollars)		
Balance at March 31, 2008	$ (164.7)	
Total realized (gains) losses included in net income	-	
Total unrealized gains (losses) included in other comprehensive income	11.1	
Total realized (gains) losses refunded to or collected from ratepayers	(32.1)	(a)
Purchase, sales and issuances of new positions, net	6.8	(b)
Transfers in and out of level 3	(6.9)	(c)
Level 3 balance at March 31, 2009	(185.8)	
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, 2009	$ -	

(a) The realized portion is the mark-to-market amount as of the beginning of each period that settled by the end of the period. Reserves and collaterals are included in the unrealized portion.
(b) The Mark-to-Market amount as of the end of this period for transactions that started after last period.
(c) The amount of $6.9 million was transferred out of Level 3 to Level 2 as of September 30, 2008.

NOTE F - EMPLOYEE BENEFITS

Summary

The Company and its subsidiaries have defined benefit pension plans covering substantially all employees. The pension plans are non-contributory and tax qualified defined benefit plans which provide all 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, non-contributory 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.

New York based pension and PBOP plans amortize prior service costs and gains and losses over a 10 year period calculated on a vintage year basis as required by the regulatory policy.

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	
	2009	2008	**2009**	2008	**2009**	2008
U.S. equities	**30%**	42%	**37%**	33%	**49%**	49%
Global equities (including U.S.)	**7%**	3%	**0%**	0%	**0%**	0%
Global tactical asset allocation	**7%**	7%	**0%**	0%	**0%**	0%
Non-U.S. equities	**11%**	13%	**17%**	17%	**21%**	21%
Fixed income	**40%**	31%	**45%**	50%	**28%**	28%
Private equity and other	**5%**	4%	**1%**	0%	**2%**	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	
	2009	2008	**2009**	2008	**2009**	2008
U.S. equities	**30%**	40%	**42%**	30%	**48%**	46%
Global equities (including U.S.)	**5%**	3%	**0%**	0%	**0%**	0%
Global tactical asset allocation	**7%**	7%	**0%**	0%	**0%**	0%
Non-U.S. equities	**10%**	14%	**12%**	15%	**20%**	21%
Fixed income	**41%**	31%	**44%**	55%	**30%**	31%
Private equity and other	**7%**	5%	**2%**	0%	**2%**	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 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. Small 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 investment committee on a quarterly basis.

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

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 fiscal years ending March 31.

	Pension benefits			
	Benefit obligation		**Net periodic benefit costs**	
	2009	2008	**2009**	2008
Discount rate	**7.30%**	6.50%	**6.50%**	6.00% - 6.50%
Rate of compensation increase	**3.50%**	3.50%-4.00%	**3.50% - 4.00%**	3.50% - 5.00%
Expected long-term rate of return on assets	**n/a**	n/a	**8.00%**	8.00%

	PBOP			
	Benefit obligation		**Net periodic benefit costs**	
	2009	2008	**2009**	2008
Discount rate	**7.30%**	6.50%	**6.50%**	6.00% - 6.50%
Expected long-term rate of return on assets	**n/a**	n/a	**6.75% - 8.25%**	7.00% - 8.25%
Health care cost trend rate				
Initial - pre 65	**8.50%**	9.00%	**9.00%**	9.00% - 9.50%
Initial - post 65	**9.50%**	10.00%	**10.00%**	10.00% - 10.50%
Ultimate	**5.00%**	5.00%	**5.00%**	5.00%
Year ultimate rate reached - pre 65	**2015**	2014	**2014**	2012
Year ultimate rate reached - post 65	**2016**	2015	**2015**	2013

The expected contributions to the Company's pension and PBOP plans during fiscal year 2010 are $698 million.

Pension Benefits

The Company's net periodic benefit cost for the fiscal years ended March 31, 2009 and 2008 included the following components:

(in millions of dollars)		2009		2008
Service Cost	$	**111.8**	$	93.2
Interest Cost		**351.0**		276.1
Expected return on plan assets		**(417.0)**		(322.7)
Amortization of prior service cost		**5.6**		5.0
Amortization of loss		**67.0**		61.8
Net period benefit costs before settlements and curtailments		**118.4**		113.4
Settlement and curtailment loss		**-**		0.7
Special termination benefits (VERO)		**75.7**		50.3
Net periodic benefit cost	$	**194.1**	$	164.4

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)		2009		2008
Accumulated benefit obligation	$	(4,794.9)	$	(5,027.6)
Reconciliation of benefit obligation:				
Benefit obligation at beginning of period		**(5,530.0)**		(2,897.2)
Service cost		**(111.8)**		(93.2)
Interest cost		**(351.0)**		(276.1)
Actuarial gain (loss)		**379.2**		163.4
Benefits paid		**442.3**		364.8
Plan amendments		**-**		(8.4)
Settlements and special termination benefits		**(53.1)**		(41.8)
Acquisition		**-**		(2,741.5)
Benefit obligation at end of period		**(5,224.4)**		(5,530.0)
Fair value of plan assets at beginning of period		**5,077.4**		2,494.8
Actual return on plan assets		**(1,331.7)**		(110.9)
Company contributions		**478.4**		437.8
Benefits paid		**(442.3)**		(364.8)
Settlements		**(26.3)**		(0.7)
Acquisition		**-**		2,621.2
Fair value of plan assets at end of period		**3,755.5**		5,077.4
Funded status	$	**(1,468.9)**	$	(452.6)

On August 24, 2007, the Company acquired KeySpan. In connection with this acquisition, the assets and benefit obligations of the plans increased in the amounts of $2.6 billion and $2.7 billion, respectively, during the fiscal year ending March 31, 2008.

As of March 31, amounts recognized on the balance sheets consist of:

(in millions of dollars)	2009	2008
Current pension liability	**$ (32.7)**	$ (19.1)
Non-current pension liability	**(1,436.2)**	(433.5)
Net amount recognized	**$ (1,468.9)**	$ (452.6)

(in millions of dollars)	2009	2008
Amount recognized in AOCI consist of:		
Net actuarial loss	**$ 2,083.3**	$ 785.9
Prior service cost	**41.9**	47.5
Net amount recognized	**$ 2,125.2 ***	$ 833.4 *

*As a result of deferral accounting treatment mandated by various state regulatory authorities, $889.6 million of this amount is reflected in regulatory assets on the Consolidated Balance Sheet. The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized during fiscal year 2010 are $171 million and $5 million, respectively.

The following pension benefit payments are expected to be paid:

(in millions of dollars)	Pension benefits
2010	$ 401.6
2011	$ 396.8
2012	$ 407.5
2013	$ 430.1
2014	$ 441.5
2015-2019	$ 2,338.9

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 and $27 million were expensed in fiscal year 2009 and 2008, respectively.

Postretirement Benefits Other than Pensions

The Company's total net periodic benefit cost of PBOPs for the fiscal years ended March 31, 2009 and 2008 included the following components:

(in millions of dollars)		2009		2008
Service cost	$	**49.3**	$	42.6
Interest cost		**220.2**		174.7
Expected return on plan assets		**(113.9)**		(101.7)
Amortization of prior service cost		**13.3**		13.3
Amortization of net loss		**50.4**		44.3
Net periodic benefit cost before special termination benefits		**219.3**		173.2
Special termination benefits (VERO)		**1.6**		1.4
Net periodic benefit cost	**$**	**220.9**	$	174.6

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

(in millions of dollars)	2009	2008
Change in benefit obligation:		
Benefit obligation at beginning of period	**$ (3,540.2)**	$ (2,216.0)
Service cost	**(49.3)**	(42.6)
Interest cost	**(220.2)**	(174.7)
Actuarial loss	**331.2**	19.0
Benefits paid	**177.8**	157.5
Medicare subsidy	**(0.5)**	(2.2)
Plan amendments	-	(0.2)
Curtailment	-	7.4
Special termination benefits (VERO)	**(1.6)**	(1.5)
Acquisitions	-	(1,286.9)
Benefit obligation at end of period	**(3,302.8)**	(3,540.2)
Change in plan assets:		
Fair value of plan assets at beginning of period	**1,474.2**	1,044.7
Actual return on plan assets	**(401.1)**	(32.8)
Company contributions	**142.0**	93.4
Benefits paid	**(177.8)**	(153.8)
Acquisitions	-	522.7
Fair value of plan assets at end of period	**1,037.3**	1,474.2
Funded status	**$ (2,265.5)**	$ (2,066.0)

On August 24, 2007, the Company acquired KeySpan. In connection with this acquisition, the assets and benefit obligations of the PBOP plans increased by $523 million and $1.3 billion, respectively, during fiscal year ending March 31, 2008.

As of March 31, amounts recognized on the balance sheets consist of:

(in millions of dollars)		2009		2008
Current liabilities	$	**(10.0)**	$	-
Noncurrent liabilities		**(2,255.5)**		(2,066.0)
Net amount recognized	**$**	**(2,265.5)**	$	(2,066.0)

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

(in millions of dollars)		2009			2008	
Amount recognized in AOCI consist of:						
Net actuarial loss	$	**726.6**		$	585.9	
Propr service cost		**79.9**			93.3	
Net amount recognized	**$**	**806.5**	*	$	679.1	*

*As a result of deferral accounting treatment mandated by various state regulatory authorities, $394.3 million of this amount is reflected in regulatory assets on the Consolidated Balance Sheet. The estimated net actuarial loss and prior service cost for the PBOP plans that will be amortized during fiscal year 2010 are estimated to be $61 million and $13 million, respectively.

As a result of the Medicare Act of 2003, the Company receives a federal subsidy for sponsoring a retiree healthcare plan that provides a benefit that is actuarially equivalent to Medicare Part D.

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**
2010	$	199.2	$	11.9
2011	$	212.3	$	13.0
2012	$	224.0	$	14.3
2013	$	233.8	$	15.7
2014	$	243.9	$	16.9
2015-2019	$	1,352.6	$	93.6

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

(in millions of dollars)		2009
Increase 1%		
Total of service cost plus interest cost	$	41.1
Postretirement benefit obligation	$	422.7
Decrease 1%		
Total of service cost plus interest cost	$	(34.3)
Postretirement benefit obligation	$	(364.7)

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 $69 million and $49 million of VERO costs for the fiscal years ended March 31, 2009 and 2008, respectively.

Additional VERO packages were offered to 80 employees during the fiscal year ending March 31, 2009. Of the eligible employees, 70 enrolled in these VEROs. Employees enrolled in the early retirement program will retire by between October 1, 2008 and December 1, 2009. The Company recorded costs of approximately $9 million related to these voluntary plans.

In March 2009, an additional VERO offer was made to 38 employees. The window for acceptance of these voluntary termination benefits will close in June 2009. As of March 31, 2009 no costs were recorded related to this VERO offer. Estimated pension and PBOP costs associated with this offer are expected to be between $2 million and $5 million.

NOTE G – INCOME TAXES

The following is a summary of the components of federal and state income tax and reconciliation between the amount of federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory level.

Total income taxes from continuing operations in the consolidated statements of income are as follows:

(in millions of dollars)		For the year ended March 31, 2009		2008
Components of federal and state income taxes:				
Current tax expense:				
Federal	$	**791.2**	$	354.4
State		**272.6**		67.5
Total current income taxes	$	**1,063.8**		421.9
Deferred tax expense (benefit):				
Federal	$	**(555.7)**	$	(74.3)
State		**(187.6)**		(2.3)
Total deferred income taxes	$	**(743.3)**		(76.6)
Total income tax expense	$	**320.5**	$	345.3

The income tax amounts included in the Statements of Income differ from the amounts that result from applying the statutory federal income tax rate to income before income tax. The following is a reconciliation between reported income tax and tax computed at the statutory rate of 35%:

(in millions of dollars)		For the year ended March 31, 2009		2008
Computed tax at statutory rate	$	**270.7**	$	337.5
Increases (reductions) in tax resulting from:				
State income tax, net of federal income tax benefit		**54.7**		39.9
Book/tax depreciation not normalized		**18.2**		16.1
Intercompany tax sharing adjustment		**(2.3)**		(17.5)
Medicare subsidy		**(14.5)**		(13.5)
Cost of removal		**(9.4)**		(10.1)
Amortization of investment tax credit, net		**(6.8)**		(6.2)
Provision to return adjustments		**(7.0)**		(2.5)
Tax audit and related reserve movements		**10.8**		-
Change in cash surrender value		**13.2**		-
All other differences		**(7.1)**		1.6
Total income taxes	$	**320.5**	$	345.3
Effective tax rate		41%		36%

At March 31, 2009 and 2008, the significant components of Company's deferred tax assets and liabilities calculated under the provisions of SFAS No.109 "Accounting for Income Taxes" were as follows:

	At March 31,	
(in millions of dollars)	2009	2008
Property related differences	$ 3,009.1	$ 2,821.2
Merger rate plan stranded costs	546.4	687.1
Property taxes	76.7	75.9
Investment Tax Credit	59.7	66.7
Employee benefits compensation	(1,052.9)	(701.5)
Reserves not currently deducted	(182.7)	(194.7)
Regulatory Assets	34.6	(89.3)
Environmental costs	65.6	24.5
Other items-net	(431.0)	(451.1)
Net deferred tax liability (asset)	2,125.5	2,238.8
Current deferred tax asset	(218.5)	(188.5)
Non-current deferred tax liability	$ 2,344.0	$ 2,427.3

Subsequent to the finalization of the purchase accounting exercise one year following the acquisition of KeySpan by National Grid plc, we performed a detailed review and reconciliation exercise of all tax related balances that resulted in further adjustments to goodwill being recorded. In aggregate the adjustments resulted in a $22 million adjustment to the provisional goodwill balance and other balance sheet accounts by like amounts that were reported on the March 2008 Consolidated Balance Sheet. This $22 million adjustment, as well as other purchase accounting entries, is reflected in the Financial Statements for the twelve months ended March 31, 2009. For further information on all purchase accounting entries please see Note L "Acquisitions."

The Company has a deferred tax asset of approximately $56 million for losses of $590 million incurred by NGUSA or its subsidiaries in the state of Massachusetts that are carried forward to offset 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, 2009, these state net operating losses expire between 2011 and 2015.

In July 2006, the FASB issued Financial Interpretation (FIN) 48, "Accounting for Uncertainty in Income Taxes," which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS 109, "Accounting for Income Taxes." FIN 48 provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, assuming the taxing authority has full knowledge of all relevant information and that any dispute with a taxing authority is resolved by the court of last resort. Income tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. Recognized tax benefits are measured as the largest amount of tax benefit that is more likely than not to be realized upon settlement with the taxing authority, assuming the taxing authority has full knowledge of all relevant information.

The Company adopted the provisions of FIN 48 on April 1, 2007. As a result of the implementation of FIN 48, the Company recognized approximately a $92 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction in retained earnings of $10.2 million, an increase to deferred tax assets of $32.3 million, and an increase to goodwill of $49.5 million to reflect the measurement under the rules of FIN 48 of uncertain tax positions related to previous business combinations. As of March 31, 2009 and 2008, the Company's unrecognized tax benefits totaled $539.4 million and $474.7 million, respectively, of which $158.5 million and $126.5 million would impact 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, 2009 and 2008:

Reconciliation of Unrecognized Tax Benefits		At March 31,		
(In millions of dollars)		**2009**		2008
Beginning balance	$	**474.7**	$	93.3
Gross increases (decreases) related to prior period		**54.9**		-
Gross increases (decreases) related to current period		**18.9**		24.0
Settlements with tax authorities		**(9.1)**		15.0
Acquisitions*		-		342.4
Ending balance at March 31, 2009	$	**539.4**	$	474.7

*On August 24, 2007, the Company acquired KeySpan. In connection with this acquisition, KeySpan's tax liabilities, including liabilities for unrecognized tax benefits, were assumed by the Company.

As of March 31, 2009, the Company has accrued for total interest of $96.4 million. During the fiscal year ended March 31, 2009, the Company recorded interest expense of $42.2 million. Effective as of April 1, 2007, the Company recognizes interest accrued related to uncertain tax positions in interest income or interest expense and related penalties if applicable in operating expenses. In prior reporting periods, the Company recognized such accrued interest and penalties in income tax expense. No penalties were recognized during the fiscal year ended March 31, 2009.

The Company and it's subsidiaries participates in filing a federal consolidated return with it's parent National Grid Holdings, Inc. ("NGHI"). Subsequent to KeySpan's acquisition on August 24, 2007, KeySpan also participates in the National Grid Holdings, Inc. ("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, 2002. During fiscal year ended March 31, 2009, NGHI consolidated group, excluding KeySpan, settled certain proposed IRS audit adjustments related to fiscal years ending March 31, 2003 and March 31, 2004 with the IRS Office of Appeals and is awaiting finalization of the settlement agreement. The Company expects to make a cash tax payment to the IRS within the next twelve months related to the 2003-2004 settlement. At that time, the Company expects to decrease its total gross unrecognized tax benefits by $79.3 million. The IRS is currently auditing the federal NGHI consolidated income tax returns, excluding KeySpan, which include the Company for March 31, 2005 through March 31, 2007. The fiscal year ended March 31, 2008, which includes KeySpan, remains subject to examination by the IRS.

The IRS has also commenced the examination of KeySpan's consolidated income tax returns for the years ended December 31, 2000 through 2006.

The Company and its subsidiaries file 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 statue of limitations.

In 2008, New York State has recently completed its audit, without change, of National Grid USA Service Company's separate company returns for the fiscal years ending March 31, 2003 through March 31, 2005. 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, the Company paid $4.8 million of its total gross unrecognized tax benefits. The fiscal years ending March 31, 2006 through March 31, 2008 remain subject to examination by New York State, and it is anticipated that the next audit cycle including the open years will commence during the next fiscal year. 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 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 year 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 will eliminate the previous separate reporting filing rules and implement 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 2009 financial statements.

NOTE H – LONG-TERM DEBT

European Medium Term Note Program:
At March 31, 2009, NGUSA 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, 2009, $93.2 million of these notes were issued and outstanding, including the impact of interest rate and currency swaps. Interest rates at March 31, 2009 ranged from 0.40% to 4.61%. At March 31, 2008, $159 million of these notes were outstanding with interest rates ranging from 3.55% to 5.51%.

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, 2009, the Company was in compliance with all covenants.

Notes Payable:
At March 31, 2009, the Company had outstanding $1,533.0 million 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.

Additionally, the Company had outstanding $1,157.9 million and $1.163.4 million of unsecured medium and long-term notes at March 31, 2009 and 2008, respectively. The interest rates on these unsecured notes ranged from 4.65% to 9.41% and the maturity dates extend from 2013 through 2035. This includes a $15 million long-term debt that 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 March 31, 2009, the total long-term debt was 17% of total capitalization. Additionally, some of these bonds have a sinking fund requirement which totaled $5.5 million during the fiscal year ended March 31, 2009.

At March 31, 2008, the Company had $3,456.3 million of secured and unsecured medium and long-term notes outstanding with interest rates ranging between 4.65% and 9.75%.

The Company repaid a $600 million Senior Note with an interest rate of 7.75% on October 1, 2008 and $160 million note with an interest rate of 4.90% on May 16, 2008.

Gas Facilities Revenue Bonds:
At March 31, 2009 and 2008, 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 was variable rate series due through July 1, 2026. The interest rate is reset weekly and ranged from 0.83% to 11.0% for the twelve months ended March 31, 2009. For the twelve months ended March 31, 2008, the interest rates ranged from 3.00% to 6.27%. The variable-rate auction bonds are currently in the auction rate mode and are backed by bond insurance. The recent turmoil in the auction rate markets has led to widespread auction failures. 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 Company's subsidiary, Brooklyn Union or the bond insurer, whichever is greater. To date, the effect on interest expense has not been material.

***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, 2009 and 2008, $155.4 million of promissory notes remained outstanding with maturity dates between 2016 and 2025. Interest rate ranges 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, 2009, the Company was in compliance with this requirement.

First Mortgage Bonds:
At March 31, 2009, the Company had outstanding $133.4 million of first mortgage bonds. Certain of the first mortgage bond indentures include, among other provisions, limitations 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, 2009, 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, 2008, $205.1 of first mortgage bonds were outstanding with interest rates ranging from 5.72% to 10.25%. The Company repaid $71.7 million of First Mortgage Bonds on their maturity dates through March 2009.

State Authority Financing Bonds:
At March 31, 2009, the Company had outstanding $1.2 billion of State Authority Financing Bonds - $716.1 million of these bonds were issued through NYSERDA and the remaining $483.6 million were issued through various other state agencies.

As noted, at March 31, 2009, $716.1 million of State Authority financing notes issued through NYSERDA were outstanding. Approximately $575 million of the Company's 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 averaged 4.22% for the fiscal year ended March 31, 2009. The bonds are currently in the auction rate mode and are backed by bond insurance. The recent turmoil in the auction rate markets has led to widespread auction failures. 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 Company or the bond insurer, whichever is greater. The effect on interest expense has not been material at this time.

The Company also has a $75.0 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which were first callable on November 1, 2008 at 102%. 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's electric subsidiaries issued two Series A bonds through NYSERDA. The first one is a $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 2.00% to 18.00% during the twelve months ended March 31, 2009, at which time the rate was 6.99%. 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 0.40% to 8.03% for the twelve months ended March 31, 2009, at which time the rate was 0.50%.

At March 31, 2009, the Company had outstanding $430.3 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode at March 31, 2009 - $410.3 million of these bonds were issued through Business Finance Authority of the State of New Hampshire, the Massachusetts Industrial Finance Authority, and the Connecticut Development Authority. Interest rates ranged from 1.70% to 0.96% for the twelve months ended March 31, 2009. There are no payments or sinking fund requirements due in 2010 through 2014. In addition, the Company has outstanding a $20 million bond issued through Massachusetts Industrial Finance Agency. The bond is due on August 1, 2014 with a variable interest rates ranging from 0.65% to 2.40% for the twelve months ended March 31, 2009. The Company repaid $20.0 million on August 1, 2008. 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 $53 million of tax exempt Electric Revenue Bonds in commercial paper mode with variable maturity dates from 2016 through 2042 and variable interest rates ranging from 0.65% to 2.83% during the twelve months ended March 31, 2009. 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 fiscal year ended March 31, 2009. The Company has Standby Bond Purchase Agreements to provide liquidity support for these bonds. See "Standby Bond Purchase Agreement" below.

At March 31, 2008, 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 2008.

Industrial Development Revenue Bonds
At March 31, 2009 and 2008, 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, 2009 and 2008, the Company had five committed bank loans outstanding totaling \$543.0 million and \$382.5 million, respectively, including the impact from interest rate and currency swaps. These loans, which mature in 2010 and 2011, are in various currencies and were used to provide funds for working capital needs. The interest rates on these bank loans are reset periodically and ranged from 0.40% to 0.55% over issued currency LIBOR rates in both years.

Inter-Company Notes Payable:
At March 31, 2009 and 2008, the Company had outstanding \$1,224.4 million of an inter-company note due to an affiliate of the Parent. This note has an interest rate of 5.52% and matures in November 2010.

Debt Maturity:
The following table reflects the maturity schedule for our debt repayment requirements, including capitalized leases and related maturities, at March 31, 2009:

(in millions of dollars)	Long-Term Debt
Repayment for fiscal years:	
2010	$ 471.4
2011	2,267.8
2012	249.6
2013	17.2
2014	255.9
Thereafter	3,546.9
	$ 6,808.8

The following table depicts the sinking fund requirements.
Sinking fund requirement

(in millions)	
Repayment for fiscal years:	
2010	$ 7.1
2011	7.1
2012	7.1
2013	7.2
2014	7.2
Thereafter	23.4
	$ 59.1

Long-term Debt:
The following tables depict the fair value of the Company's long-term debt at March 31, 2009.

(in millions of dollars)		2009
European Medium Term Notes	$	92.9
Long-Term Notes		2,523.6
Gas Facilities Revenue Bonds		610.2
Promissory Notes to LIPA		147.9
First Mortgage Bonds		127.2
State Authority Financing Bond		1,189.2
Industrial Development Revenue Bonds		109.0
Committed Facilities		529.5
Inter-Company Notes		1,224.4
	$	6,553.9

Standby Bond Purchase Agreement:
At March 31, 2009, three of the Company's subsidiaries had a Standby Bond Purchase facility with banks totaling $325 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 downgrading or upgrading of the entity's rating. The current annual facility fee is 0.100% based on Mass Electric's and NEP's credit rating of A3 by Moody's Investor Services and A- by Standard & Poor's.

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, 2009, the Company's subsidiaries named in the facility were in compliance with this covenant. The agreement expires on November 29, 2009. There were no borrowings under the standby bond purchase agreement at March 31, 2009.

Credit Facility Agreements:
At March 31, 2009, the Company and certain of its subsidiaries had a Credit Facility agreement with a number of banks totaling $355 million. The agreement provides for an aggregate letter of credit limit of $125 million and a borrowing limit of $230 million for one subsidiary within which is included a letter of credit limit of $30 million. The facility fee and utilization fee for the facility are based on the credit rating of the subsidiaries and is increased or decreased based on a downgrading or upgrading of the rating. The current annual facility fee is 0.100% and the utilization fee is 0.125% based on the subsidiaries credit rating of A3 by Moody's Investor Services and A- by Standard & Poor's. The facility contains certain financial covenants that require the Company and certain of its subsidiaries named in the facility to maintain a debt to total capitalization ratio of no more than 65% at the last day of each fiscal quarter. At March 31, 2009, the Company and each of its subsidiaries named in the facility were in compliance with this covenant. The agreement expires on November 29, 2009. At March 31, 2009, $63 million of letters of credit have been issued.

On January 31, 2008, National Grid plc announced that it would increase its dividend for fiscal year 2008 by 15% and attempt to grow its dividends 8% per annum thereafter. Following this announcement, Moody's Investors Service changed the outlook for National Grid plc and its rated subsidiaries, including the Company's, debt ratings to negative outlook from stable due to the perceived aggressiveness of the dividend policy.

NOTE I – SHORT-TERM DEBT

Commercial Paper and Revolving Credit Agreements

Commercial Paper

At March 31, 2009, the Company has a commercial paper program totaling $2.0 billion. In addition, the Company has commercial paper program totaling $1.5 billion entered into by KeySpan prior to acquisition. The KeySpan program is scheduled to fully expire by 2010. The Company does not intend to issue commercial paper under the KeySpan's program and does not intend to renew these agreements upon their expiration.

NGUSA's commercial paper program. In support of NGUSA's commercial paper program, the Company was a named borrower under a credit facility in the name of the Parent totaling $850 million, with the full amount of the facility being available to the Company. This facility supports the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facility expires in November 2009.

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 0.325% or 0.375% if over $750 million has been borrowed under the facility. The current annual fee is 0.09%. 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 there under, as well as possible cross defaults under other debt agreements. At March 31, 2009, 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 $850 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, 2009, there were no borrowings on the National Grid USA commercial paper program.

KeySpan's commercial paper program. In support of KeySpan's commercial paper program, at March 31, 2009, KeySpan had two credit facilities totaling $1.5 billion - $920 million expiring in 2010, and $580 million expiring in 2009, which continue to support KeySpan's commercial paper program for ongoing working capital needs.

The fees for the facilities are based on KeySpan's current credit ratings and are increased or decreased based on a downgrading or upgrading of its ratings. The current annual facility fee is 0.08%. Both credit facilities allow for KeySpan to borrow using several different types of loans; specifically, Eurodollar loans, ABR loans, or competitively bid loans. Eurodollar loans are based on the Eurodollar rate plus a margin that is tied to our applicable credit ratings. We do not anticipate borrowing against these facilities; however, if for any reason we were not able to issue sufficient commercial paper or source funds from other sources, this facility could be drawn to meet cash requirements.

The facilities contain certain affirmative and negative operating covenants, including restrictions on KeySpan's ability to mortgage, pledge, encumber or otherwise subject its utility property to any lien, as well as certain financial covenants that require us to, among other things, maintain a consolidated indebtedness to consolidated capitalization ratio of no more than 65% at the last day of any fiscal quarter. 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, 2009, KeySpan was in compliance with all covenants.

Subject to certain conditions set forth in the credit facility, KeySpan has the right, at any time, to increase the commitments under the $920 million facility up to an additional $300 million. In addition, KeySpan has the right to request that the termination date be extended for an additional period of 365 days prior to each anniversary of the closing date. This extension option, however, requires the approval of lenders holding more than 50% of the total commitments to such extension request. Under the agreements, KeySpan has the ability to replace non-consenting lenders with other pre-approved banks or financial institutions.

At March 31, 2009, there were no borrowings on the KeySpan commercial paper program. At March 31, 2008, $286.8 million of commercial paper was outstanding.

Uncommitted Facility Agreements

At March 31, 2009, the Company had uncommitted loan facilities totaling $720 million available from five banks. There were no borrowings at March 31, 2009. 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 for 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. 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 $4 billion from the Parent (through intermediary entities) and certain other subsidiaries of the Parent, including for the purpose of funding the money pool, if necessary. At March 31, 2009, the Company had borrowed $1.9 billion under this arrangement. Additionally, the Company has a $100.8 million promissory note outstanding with National Grid Holdings Inc., the Company's immediate parent company. At March 31, 2008, the Company had borrowed $850 million under this arrangement and had a $262 million promissory note outstanding with National Grid Holdings Inc.

NOTE J – 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, 2009 and 2008 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	**2009**	2008	**2009**	2008	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**	137,139	**13.7**	13.7	104.850
3.90% Series	Niagara Mohawk	**95,171**	94,967	**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**	372,421	$ **34.8**	$ 34.8	

NOTE K – DISCONTINUED OPERATIONS

National Grid Wireless (Wireless) was a subsidiary of the Company that owned, operated and managed towers and other communications structures. Wireless also managed a fiber optic telecommunications system in the Northeastern United States.

On August 15, 2007, the Company completed the sale of its wireless infrastructure operations for proceeds of approximately $290 million. The final sale resulted in a pre-tax gain in fiscal 2008 of approximately $24 million primarily reflecting final working capital adjustments and other adjustments to the estimated selling price.

On August 22, 2007, the NYPSC approved the merger application between KeySpan and National Grid plc. As a condition of the approval of the KeySpan Acquisition, the Company was required to divest the Ravenswood Generating Station. In addition, National Grid plc, determined that the KeySpan telecommunications and engineering subsidiaries did not fit into the post-merger business model. As such, the Company exited these businesses. The operating results and financial positions of these companies are reflected as discontinued operations on the Consolidated financial statement in the appropriate periods presented. KeySpan's telecommunications company and one of the engineering companies were sold in late July 2008 for a total cash consideration of approximately $43 million which was completed on July 25, 2008. The assets and liabilities of this subsidiary were fair valued at August 24, 2007 and as a result the final sale had no material impact on the Consolidated Income Statement.

On August 26, 2008, the sale of KeySpan Ravenswood, LLC was completed for total cash consideration of $2.9 billion. In advance of this sale, we terminated the Ravenswood Master Lease, the lease under which the Company operated the Ravenswood facility, on June 20, 2008, which was otherwise due to expire in 2009. The transaction also provided for the restructuring and transfer of our interest in the Ravenswood Expansion. However, we will remain responsible for all future lease payments under the sales/leaseback arrangement through May 2040. The total consideration received from the Ravenswood Sale Transaction included a prepayment from TransCanada of the future payments under the sales/leaseback arrangement on a present value basis.

The information below highlights the major classes of assets and liabilities of the discontinued operations, as well as major income and expense captions (in millions).

Income Statement Data

(in millions of dollars)	For the year ended March 31, 2009	2008
Total operating revenues	$ 154.5	$ 374.4
Total operating expenses	111.2	315.2
Operating income	43.3	59.2
Total other income (expense)	(1.2)	14.0
Income (loss) before income taxes	42.1	73.2
Income tax provision (benefit)	17.5	30.2
Net income	$ 24.6	$ 43.0

Balance Sheet Data

(in millions of dollars)	At March 31, 2009	2008
ASSETS		
Total current assets	$ 15.1	$ 167.1
Deferred Charges	11.7	65.6
Property and Other Long Term Assets	3.2	2,792.7
LIABILITIES AND STOCKHOLDER'S EQUITY		
Total current liabilities	$ 12.7	$ 608.1
Deferred Credits and Other Liabilities	-	1,252.7

NOTE L –ACQUISITIONS

The acquisition of KeySpan was completed on August 24, 2007 at a total cost of $7.6 billion. The transaction was accounted for using the purchase method of accounting for business combinations in accordance with SFAS 141 "Business Combination." The purchase price of $7.6 billion was allocated to KeySpan's assets and liabilities based on their estimated fair values at the date of acquisition. The historical cost basis of KeySpan's assets and liabilities associated with its gas distribution businesses, with minor exceptions, was determined to represent fair value due to the existence of regulatory-approved rate plans based upon the recovery of historical costs and a fair return thereon. Further, the historical cost basis of assets and liabilities associated with electric generating units on Long Island that are under long-term power supply agreements with LIPA, with minor exceptions, was determined to represent fair value due to the Power Supply Agreement with LIPA that provides for the recovery of historical costs and a fair return thereon.

The net assets acquired were initially assigned a provisional goodwill value of $3.9 billion. During the post acquisition period, the provisional fair values applied were reviewed and a number of adjustments were made to those provisional values as a result of better information being available. KeySpan has been consolidated into National Grid plc from August 24, 2007 onward.

The following table summarizes the fair value adjustments and calculation of goodwill:

(in millions of dollars)	Provisional Goodwill at March 31, 2008	Goodwill Adjustments	Final Goodwill at March 31, 2009
Purchase Price	$ 7,574.3	$ -	$ 7,574.3
KeySpan's Consolidated Equity at August 24, 2007	4,268.9	-	4,268.9
Goodwill Prior to Acquisition	1,665.9	-	1,665.9
KeySpan's Adjusted Consolidated Equity	2,603.0	-	2,603.0
Goodwill before Fair Value Adjustments	4,971.3	-	4,971.3
Fair Value Adjustments			
Assets Impacted:			
Accounts Receivable	(4.9)	(8.5)	(13.4)
Materials and supplies	296.2	(171.5)	124.7
Equity Investments and Other	(11.3)	-	(11.3)
Property Plant and Equipment	224.4	(4.6)	219.8
Regulatory Assets	236.8	101.4	338.2
Deferred Charges	(32.8)	-	(32.8)
Liabilities Impacted:			
Accounts Payable	(46.4)	(16.8)	(63.2)
Taxes Accrued	(130.1)	4.2	(125.9)
Regulatory Liabilities	(189.6)	-	(189.6)
Postretirement Benefits and Other Reserves	(147.8)	(147.8)	(295.6)
Deferred Credits and Other Liabilities	(612.2)	149.4	(462.8)
Deferred Income Tax	(50.9)	85.4	34.5
Long-term Debt	(58.2)	-	(58.2)
Net Adjustment	(526.8)	(8.8)	(535.6)
Intangible Asset Adjustment	186.1	(1.4)	184.7
Assets Held for Sale Fair Value Adjustments	1,373.7	(38.9)	1,334.8
Total Goodwill After Acquisition	$ 3,938.3	$ 49.1	$ 3,987.4

A discussion of the more significant fair value adjustment follows.

Materials and supplies: KeySpan is entitled to emission credits associated with its electric generating facilities on Long Island. These emission credits were originally valued at $296 million on August 24, 2007. The fair value of these credits was subsequently reduced to reflect a decision of the DC circuit court to vacate the Clean Air Interstate Rule (CAIR) resulting in a revised fair value of $125 million. As agreed to in the service agreements with LIPA, LIPA is entitled to a portion of these credits which were also reduced appropriately and are reflected in deferred credits and other liabilities. Subsequent to the final valuation, the emission credits were further devalued, resulting in a $24.6 million impairment charge which is reflected in the 2009 Consolidated Statement of Income.

Equity Investments and Other: KeySpan owns a 600,000 barrel liquefied natural gas (LNG) storage and receiving facility in Providence, Rhode Island, through its wholly owned subsidiary

KeySpan LNG. KeySpan LNG proposed to upgrade the liquefied natural gas facility to accept marine deliveries and to triple vaporization (or regasification) capacity to provide these services. The proposed upgrade was subject to numerous FERC proceedings, as well as proceedings with the Federal District Court in Rhode Island. At the time of the KeySpan acquisition, National Grid plc decided not to pursue the upgrade of the LNG facility. As a result, deferred project costs of $11.3 million were written-off as a direct charge to equity.

Property, Plant and Equipment: As required by SFAS 141, upon acquisition KeySpan calculated the fair value of its property, plant and equipment for all its business segments. As noted previously, the historical cost basis of KeySpan's assets and liabilities associated with its gas distribution businesses, with minor exceptions, was determined to represent fair value due to the existence of regulatory-approved rate plans based upon the recovery of historical costs and a fair return thereon. Further, the historical cost basis of KeySpan's electric generating units on Long Island that are under long-term power supply agreements with LIPA, with minor exceptions, was determined to represent fair value. The historical cost basis of property, plant and equipment related to KeySpan's non-regulated business, primarily land, was increased by $260 million to represent fair value at date of acquisition.

The Company maintains gas production and development activities through its two wholly-owned subsidiaries - KeySpan Exploration and Seneca-Upshur. At the end of fiscal year 2008, the Company estimated that the capitalized costs associated with natural gas and oil reserves of these entities did not exceed the ceiling test limitation. However, the fair value exercise associated with SFAS 141 required a higher level of estimated operating costs and capital expenditures, compared to the same estimates required to be used in the ceiling test calculation resulting in a write down of $30 million to the natural gas and oil reserves.

As part of its synergy savings strategy, the Company is relinquishing three floors in its Brooklyn headquarters at MetroTech. As a result, the Company reduced its property, plant and equipment by $10.3 million associated with past leasehold improvement costs. Additionally, the Company incurred a $10 million fee in consideration for the early termination of part of its lease of the MetroTech office. This fee has been recorded as a current liability on the Consolidated Balance Sheet.

Regulatory Assets and Other Reserves: Upon acquisition, KeySpan made certain adjustments to its pension and other postretirement reserve balances, as well as to its environmental reserve balances. KeySpan adjusted certain assumptions underlying the calculations for its pension and other postretirement reserves to align those assumptions with NGUSA's pension and postretirement reserve assumptions where appropriate. This alignment reduced KeySpan's pension and other postretirement reserves approximately $180 million. Certain gas distribution subsidiaries are subject to deferral accounting requirements mandated by the various state regulators for pension costs and other postretirement benefit costs. As a result, approximately $94 million of the decrease to the pension and other postretirement reserves was recorded as an "offset" to regulatory assets.

KeySpan also adjusted certain assumptions underlying the calculations for its environmental reserve to align those assumptions with NGUSA's environmental reserve assumptions where appropriate. This alignment increased the Company's environmental reserve approximately $447 million (originally $343 million). Certain gas distribution subsidiaries are subject to deferral accounting requirements mandated by the various state regulators for environmental costs. As a result, approximately $432 million of the increase to the environmental reserve was recorded as an "offset" to regulatory assets.

In fiscal year 2008, the United States Court of Appeals for the District of Columbia Circuit (Court) denied the petitions of the New York Independent System Operator ("NYISO") and various New York Transmission Owners seeking refunds for charges in the January - March 2000 reserve market. As a result of this favorable decision, KeySpan reversed a previously established reserve for these proceedings of $18.1 million. As required by SFAS 141, this amount was recorded as a direct benefit to equity. Further, certain reserve balances related to injuries and damages insurance, potential legal fees and emission credits were adjusted totaling $46 million. Neither the $18.1 million NYISO reserve adjustment nor the other reserve adjustments of $46 million impacted regulatory assets.

Accounts Payable: In March 2008, the FERC approved the NYISO In-City capacity mitigation measures and revised the In-City capacity bid caps. KeySpan had a derivative swap instrument with Morgan Stanley and the revised bid caps resulted in the derivative swap instrument's floating price being set to equal the strike price, thereby eliminating all cash flow between the two parties for the remaining term of the swap agreement. The fair value of this derivative instrument was calculated to be a liability of $17.9 million at August 24, 2007; such amount was recorded as a current liability and a direct charge to equity.

Prior to the KeySpan Acquisition, KeySpan had a proposed project for the construction of a 250 MW combined cycle electric generation plant. In anticipation of this facility, KeySpan purchased a gas turbine generator several years ago. KeySpan and LIPA executed a "memo of understanding" for a power purchase agreement (PPA) in 2001; however the PPA was never executed by LIPA. As previously noted, the NYPSC ordered the Company to divest the Ravenswood Generating Station to mitigate concerns on vertical market power. The Company therefore determined that it was highly unlikely that a new investment in electric generation by National Grid plc would be possible. As a result, a $7.5 million current liability was recorded for consideration of contract breakage costs associated with a maintenance contract for the gas turbine generator.

The Ravenswood Generating Station was sold to Transcanada Corporation in August 2008. The Company provided Transcanada with financial services for a limited period of time following the sale at an agreed to fixed fee and accrued $10 million for potential unrecovered costs associated with these services.

As discussed in Note C, "Commitments and Contingencies," on May 31, 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. A $5.3 million current liability was recorded representing the fair value for estimated legal fees associated with this proceeding.

Additionally, as discussed in the Property, Plant and Equipment section above, the Company recorded a $10 million liability related to its Brooklyn office facility.

Regulatory Liabilities: As part of the NYPSC approval of the KeySpan Acquisition, a five year rate plan was agreed to by KeySpan, the NYPSC and the other parties for Brooklyn Union and KeySpan Gas East. The rate plans went into effect on January 1, 2008 and included approximately $189.6 million of certain ratepayer refunds.

Deferred Income Taxes: The adjustments to deferred income taxes reflect, in part, the results of the purchase accounting and fair value exercise undertaken for certain balance sheet accounts. Additionally, as a consequence of a detailed review and reconciliation process of tax related balances, we made adjustments to certain tax balances that resulted in a $22 million goodwill adjustment.

Long-term Debt: As part of the fair value exercise, KeySpan calculated the fair value of outstanding debt for all its non-regulated enterprises. This analysis required KeySpan to eliminate prior balances associated with debt discounts and premiums, as well as settled interest rate hedges that were being amortized. A $58 million long-term liability was recorded as a result of this fair value analysis. The long-term debt associated with certain regulated gas distribution businesses were not fair valued due to the existence of regulatory-approved rate plans that provide for the recovery of historical costs.

Intangible Asset: Certain intangible assets were created as a result of the acquisition. The MSA Agreement and the EMA Agreement with LIPA were valued at $150.7 million. These intangible assets will be amortized over 20 years and 6 years respectively. Additionally, intangible assets of $35.4 million were recorded for appliance service subsidiaries. These intangible assets relate to contractual relationships and plumbing licenses. The intangible asset associated with the plumbing license will be amortized over eight years, while the intangible asset associated with contractual relationships has an indefinite life.

Fair Value of Assets Held for Sale: As part of the purchase accounting exercise and in conjunction with the sale of the Ravenswood Generating Station and the engineering and telecommunications companies, an evaluation of the fair value of these investments was conducted. The evaluation resulted in an increase to the net book value of these companies of approximately $1.3 billion, net of deferred taxes and estimated selling costs.

Other Items:
During the post acquisition period, certain adjustments were made to assets held for sale as a result of better information being available. These adjustments amounted to $38.9 million. Additionally, as discussed in Note C, "Commitments and Contingencies" the Company will continue to be responsible for lease payments under the Sale/Leaseback arrangement associated with the Ravenswood Expansion throughout the remaining life of the arrangement. The remaining lease payments were valued at $363 million; such amount has been recorded in deferred credits and other liabilities.

NOTE M –OTHER MATTERS

On July 20, 2009, Moody's Investors Service changed the outlook for National Grid plc and its rated subsidiaries, including the company's debt ratings to stable outlook from negative as a result of Moody's review of the company's results for FY2008/09 and medium-term forecasts.

In August 2009, a subsidiary of the Company issued $750 million of long-term debt at 4.881% with a maturity date of August 15, 2019. Additionally, in September 2009 the same subsidiary issued $500 million of long-term debt at 3.553% with a maturity date of October 1, 2014. The debt is not registered under the U.S. Securities Act of 1933 ("Securities Act") and was sold in the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to certain non-U.S. persons in transactions outside the United States in reliance on Regulation S under the Securities Act.