New England Power Company

Financial Statements

For the year ended March 31, 2010

New England Power Company

TABLE OF CONTENTS

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
PricewaterhouseCoopers Center
300 Madison Avenue
New York NY 10017
Telephone (646) 471 3000
Facsimile (813) 286 6000

Report of Independent Auditors

To the Stockholders and Board of Directors of
New England Power Company:

In our opinion, the accompanying balance sheets and related statements of income, of comprehensive income, of retained earnings, of capitalization and of cash flows present fairly, in all material respects, the financial position of New England Power Company (the "Company") at March 31, 2010 and 2009, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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.

New England Power Company engages in significant transactions with affiliates.

PricewaterhouseCoopers LLP

July 9, 2010

New England Power Company

BALANCE SHEETS

At March 31 (in thousands of dollars)	**2010**	2009
Assets		
Current assets:		
Cash and cash equivalents	**$ 102**	$ 310
Restricted cash	**36**	36
Accounts receivable:		
Money pool	**144,675**	278,625
Affiliated companies	**24,682**	9,441
Other	**37,846**	38,557
Total accounts receivable	**207,203**	326,623
Materials and supplies	**4,278**	3,855
Prepaid and other current assets	**51,778**	231
Derivative contracts	**508**	-
Current portion of regulatory assets	**48,432**	48,364
Total current assets	**312,337**	379,419
Property, plant and equipment		
Utility plant, at original cost	**1,541,420**	1,405,077
Less accumulated depreciation	**(296,851)**	(278,905)
Net utility plant	**1,244,569**	1,126,172
Equity investments in nuclear power companies and other	**14,291**	14,975
Long-term and deferred assets		
Derivative contracts	**604**	-
Regulatory assets	**385,933**	422,982
Deferred charges and other assets	**3,882**	2,310
Goodwill	**337,614**	337,614
Total long-term and deferred assets	**728,033**	762,906
Total assets	**$ 2,299,230**	$ 2,283,472

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

New England Power Company

BALANCE SHEETS

At March 31 (in thousands of dollars)	**2010**	2009
Liabilities and Capitalization		
Current liabilities:		
Accounts payable	**$ 26,337**	$ 29,843
Accrued taxes	**1,916**	5,083
Current portion of deferred federal and state income taxes	**2,497**	3,434
Accrued interest	**162**	565
Current portion of accrued Yankee nuclear plant costs	**14,939**	14,846
Current portion of purchase power obligations	**2,521**	4,035
Current portion of derivative instruments	**31,480**	29,483
Other accrued expenses	**6,680**	5,082
Customer deposits	**741**	685
Total current liabilities	**87,273**	93,056
Deferred credits and other liabilities		
Deferred federal and state income taxes	**238,731**	174,052
Unamortized investment tax credits	**5,375**	5,778
Accrued Yankee nuclear plant costs	**66,665**	80,870
Purchased power obligations	**7,312**	9,635
Derivative instruments	**161,142**	145,027
Regulatory liabilities	**111,160**	127,504
Cost of removal regulatory liability	**24,764**	23,181
Other reserves and deferred credits	**81,564**	66,877
Total deferred credits and other liabilities	**696,713**	632,924
Capitalization:		
Common stock, par value $20 per share,		
Authorized – 6,449,896 shares		
Outstanding – 3,619,896 shares	**72,398**	72,398
Other paid in capital	**733,545**	733,545
Retained earnings	**297,595**	340,448
Accumulated other comprehensive income (loss)	**265**	(338)
Total common equity	**1,103,803**	1,146,053
Cumulative preferred stock, par value $100 per share	**1,112**	1,112
Long-term debt	**410,329**	410,327
Total capitalization	**1,515,244**	1,557,492
Total liabilities and capitalization	**$ 2,299,230**	$ 2,283,472

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

New England Power Company

STATEMENTS OF INCOME

Year ended March 31 (in thousands of dollars)	**2010**	2009
Operating revenue	**$ 384,419**	$ 418,359
Operating expenses:		
Purchased electric energy:		
Contract termination charges and nuclear unit shutdown charges	**20,001**	24,635
Other	**71,438**	100,440
Other operation and maintenance	**89,379**	89,752
Amortization of stranded costs	**8,836**	9,683
Depreciation and amortization	**30,405**	27,400
Taxes, other than income taxes	**22,449**	21,689
Total operating expenses	**242,508**	273,599
Operating income	**141,911**	144,760
Interest (income) expense:		
Other income, net	**1,583**	(8,335)
Interest on long-term debt	**5,704**	7,679
Other interest	**(3,360)**	1,934
Total interest (income) expense	**3,927**	1,278
Income taxes		
Current	**(26,335)**	32,001
Deferred	**82,105**	21,211
Total income taxes	**55,770**	53,212
Net income	**$ 82,214**	$ 90,270

STATEMENTS OF COMPREHENSIVE INCOME

Year ended March 31 (in thousands of dollars)	**2010**	2009
Net income	**$ 82,214**	$ 90,270
Other comprehensive income (loss), net of taxes:		
Unrealized gain/(loss) on securities, net of taxes of $389 and $287, respectively	**719**	(444)
Reclassification adjustment for gain/(loss) included in net income net of taxes of $76 and $(10), respectively	**(117)**	15
Total other comprehensive income/(loss) :	**602**	(429)
Comprehensive income	**$ 82,816**	$ 89,841

STATEMENTS OF RETAINED EARNINGS

Year ended March 31 (in thousands of dollars)	**2010**	2009
Retained earnings at beginning of year	**$ 340,448**	$ 250,245
Net income	**82,214**	90,270
Dividends declared on cumulative preferred stock	**(67)**	(67)
Dividends declared on common stock	**(125,000)**	-
Retained earnings at end of year	**$ 297,595**	$ 340,448

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

New England Power Company

STATEMENTS OF CASH FLOWS

Year ended March 31 (in thousands of dollars)		2010		2009
Operating activities				
Net income	**$**	**82,214**	$	90,270
Adjustments to reconcile net income to net cash provided by operating activities:				
Amortization of stranded costs		**8,836**		9,683
Depreciation and amorization		**30,405**		27,400
Deferred income taxes and investment tax credit, net		**82,105**		20,421
Allowance for funds used during construction		**(3,212)**		(3,661)
Changes in assets and liabilities:				
Accounts receivable		**711**		(4,400)
Accounts receivable from affiliates		**(15,241)**		-
Prepaid and other current assets and fuel, materials and supplies		**(25,086)**		746
Regulatory assets		**(4,348)**		(9,626)
Accounts payable		**(37,859)**		7,364
Other current liabilities		**(2,424)**		(3,139)
Other non-current liabilities		**14,084**		7,091
Other, net		**(3,233)**		(3,743)
Net cash provided by operating activities		**126,952**		138,406
Investing activities				
Plant expenditures, excluding allowance for funds used during construction		**(135,829)**		(146,745)
Other investing activities		**(214)**		2,082
Payments received from moneypool		**133,950**		6,300
Net cash used in investing activities		**(2,093)**		(138,363)
Financing activities				
Dividends paid on common stock		**(125,000)**		-
Dividends paid on cumulative preferred stock		**(67)**		(67)
Net cash provided by financing activities		**(125,067)**		(67)
Net decrease in cash and cash equivalents		**(208)**		(24)
Cash and cash equivalents at beginning of year		**310**		334
Cash and cash equivalents at end of year	**$**	**102**	$	310
Supplementary information:				
Interest paid; less amounts capitalized	**$**	**5,197**	$	9,039
Federal and state income taxes paid to parent	**$**	**2,369**	$	33,753
Dividends received from equity method investments	**$**	**859**	$	-
Capital-related accruals included in Accounts payable	**$**	**7,280**	$	130

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

New England Power Company

STATEMENTS OF CAPITALIZATION

At March 31 (in thousands of dollars)	2010	2009	2010	2009
Common stockholder's equity				
Common stock, par value $20 per share,				
Number of shares issued	**3,619,896**	3,619,896		
Amount			**$ 72,398**	$ 72,398
Other paid-in capital			**733,545**	733,545
Retained earnings			**297,595**	340,448
Accumulated other comprehensive income/ (loss)			**265**	(338)
Total common stockholder's equity			**1,103,803**	1,146,053
Cumulative preferred stock, par value $100 per share				
Number of shares outstanding	**11,117**	11,117		
Amount			**1,112**	1,112
Long-term debt				
Pollution control revenue bonds				

Series	Rate %	Maturity	2010	2009
CDA (a)	Variable	October 15, 2015	**38,500**	$ 38,500
MIFA 1 (b)	Variable	March 1, 2018	**79,250**	79,250
BFA 1 (c)	Variable	November 1, 2020	**135,850**	135,850
BFA 2 (c)	Variable	November 1, 2020	**50,600**	50,600
MIFA 2 (b)	Variable	October 1, 2022	**106,150**	106,150
Unamortized discounts			**(21)**	(23)
Amount			**410,329**	410,327
Total capitalization			**$ 1,515,244**	$ 1,557,492

(a) CDA = Connecticut Development Authority
(b) MIFA = Massachusetts Industrial Finance Authority (now known as Massachusetts Development Finance Agency)
(c) BFA = Business Finance Authority of the State of New Hampshire

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

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a. Nature of Operations

New England Power Company's ("NEP", the "Company", "we", "us" and "our") business is the transmission of electricity in wholesale quantities to other electric utilities. The Company is a wholly-owned subsidiary of National Grid USA ("NGUSA"), a utility holding company with regulated subsidiaries engaged in the generation, transmission, distribution and sale of both natural gas and electricity in New England and New York State. NGUSA is a wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales. Approximately 80% of NEP's local transmission service is provided to the following wholly-owned subsidiaries of NGUSA: Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company and the Narragansett Electric Company. The Company owns minority equity interests in three companies which own nuclear generating facilities that are permanently retired and are conducting decommissioning operations (see Note 5 - Other investments).

b. Basis of Presentation

The Company's accounting policies conform to generally accepted accounting principles in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities (see Note 2 – Rates and regulatory), and are in accordance with the accounting requirements and ratemaking practices of the applicable regulatory authorities. The Company applies the provisions of the Financial Accounting Standards Board ("FASB") guidance related to the accounting for the effects of 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.

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

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

The Company has evaluated events or transactions that occurred after March 31, 2010 through July 9, 2010 for potential recognition or disclosure in the financial statements. There were no subsequent events that needed to be recognized.

c. Accounting for the Effects of Rate Regulation

The Federal Energy Regulatory Commission (FERC) has jurisdiction over certain of the Company's activities, including (i) regulating certain transactions among our affiliates; (ii) governing the issuance, acquisition and disposition of securities and assets by certain of our public utility subsidiaries; and (iii) approving certain utility mergers and acquisitions (See Note 2 - Rates and regulatory).

The Company is a Massachusetts corporation qualified to do business in Massachusetts, New Hampshire, Connecticut, Rhode Island, Maine and Vermont. The Company is also subject to the jurisdiction of the regulatory Commissions of these states (except Connecticut). In addition, the Company is subject to the Nuclear Regulatory Commission ("NRC").

d. Revenue Recognition

The Company has two primary sources of revenue: transmission and stranded cost recovery. Much of the Company's revenues are derived from affiliated companies. Transmission revenues are based on a formula rate that recovers the Company's actual costs plus a return on investment. Stranded cost recovery revenues are collected through a contract termination charges ("CTC"), which is billed to former wholesale customers of the Company in connection with the Company's divestiture of its electricity generation investments.

e. Property, Plant and Equipment

The cost of additions to utility plant and replacements of retirement units of property are capitalized. Costs include direct material, labor, overhead, and the allowance for funds used during construction (AFUDC as discussed 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.

f. Goodwill and Other Intangible Assets

Goodwill: In accordance with current accounting guidance for goodwill and other intangible assets, the Company tests goodwill for impairment on an annual basis and on an interim basis when certain events or circumstances exist. Goodwill impairment is determined by comparing the estimated fair value of a reporting unit with its respective book value. If the estimated fair value exceeds the book value, goodwill at the reporting unit level is not deemed to be impaired. If the estimated fair value is below book value, however, further analysis is required to determine the amount of the impairment. Additionally, if the forecasted returns utilized in the analysis are not achieved, an impairment of goodwill may result. For example, within our calculation of forecasted returns, we have made certain assumptions around the amount of pension and environmental costs to be recovered in future periods. Should we not benefit from improved rate relief in these areas, the result could be a reduction in fair value of the Company, which in turn could give rise to an impairment of goodwill.

The Company utilizes a discounted cash flow approach incorporating its most recent business plan forecasts together with a projected terminal year calculation in the performance of the annual goodwill impairment test. Critical assumptions used in the Company's analysis include a discount rate of 6% and a terminal year growth rate of 3% based upon expected long-term average growth rates. Our forecasts assume long-term recovery and rate of returns that are in line with historical levels within the utility industry. The resulting fair value of the annual analysis determined that no adjustment of the goodwill carrying value was required.

Intangible assets: Amortizable intangible assets are amortized over their estimated useful lives and reviewed for impairment on an interim basis when certain events or circumstances exist. For amortizable intangible assets, an impairment exists when the carrying amount of the intangible asset exceeds its fair value. An impairment loss will be recognized only if the carrying amount of the intangible asset is not recoverable and exceeds its fair value. The carrying amount of the intangible asset is not recoverable if it exceeds the sum of the expected undiscounted cash flows.

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

g. Cash and Cash Equivalents

The Company classifies short-term investments with a maturity of 90 days or less at time of purchase as cash equivalents.

h. Income and Excise Taxes

Regulated federal and state income taxes are recorded under the current accounting provisions of the accounting and reporting of income taxes. Income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred investment tax credits are amortized over the useful life of the underlying property. The Company follows the accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected on the Company's balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. It addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties. (See Note 7 - Income Taxes, for the impact of the adoption of the FASB accounting guidance).

i. Derivatives

The Company accounts for derivative financial instruments under the FASB guidance relating to the accounting for derivatives and hedging activities. The provisions of this guidance dictate that all derivatives, except those qualifying for the normal purchase/normal sale exception, are to be recognized on the balance sheet at their fair value. Fair value is determined using current quoted market prices, when available. When current quoted market prices are not available, fair value is determined using valuation models which require the use of estimates and assumptions. Since the Company's rate agreement provides for the pass through of derivative gains and losses, the Company applies the requirements of the FASB guidance on derivatives and hedging activities and records an offsetting regulatory asset or regulatory liability associated with the fair value of its derivative instruments.

j. Comprehensive Income/(Loss)

Comprehensive income/(loss) 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/(loss) is reported net income/(loss), the other component of comprehensive income/(loss) relates to changes in unrealized gains/(losses) associated with certain investments held as available for sale. (See Note 10 - Accumulated Other Comprehensive Income (Loss)).

k. Employee Benefits

In December 2006, NGUSA adopted the provisions of the FASB accounting guidance relating to defined benefit pensions and other postretirement benefit plans which requires employers to fully recognize all postretirement plans' funded status on the balance sheet as a net liability or asset and required an offsetting adjustment to accumulated other comprehensive income in shareholders' equity upon implementation. Consistent with past practice, NGUSA values its pension and other postretirement assets using the year-end market value of those assets. Benefit obligations are also measured at year-end. (See Note 3 - Employee Benefits, for additional details on NGUSA's pension and other postretirement plans.)

l. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date - exit price. The determination of the fair value incorporates various factors required including not only the credit standing of the counterparties involved but also the impact of the Company's nonperformance risk on its liabilities. To increase consistency and comparability in fair value measurements, a fair value hierarchy was established that prioritizes the inputs to valuation techniques used to measure fair value into three levels. The following is a fair value hierarchy:

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

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

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

m. Reclassifications

Certain amounts from prior years have been reclassified in the accompanying financial statements to conform to the current year presentation. The Company has also made other immaterial adjustments to conform certain amounts from prior years to the current year presentation.

n. Inventory

Inventory is stated primarily at the lower of cost or market value under the first-in-first-out method. The Company's policy is to write-off obsolete inventory.

o. Equity Investments and Other

The Company owns as part of its 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 the FASB guidance on the accounting for the purchase of life insurance. As such, increases and decreases in the

value of these assets are recorded through earnings in the Company's Statements of Income - other income and (deductions) concurrent with the change in the value of the underlying assets.

p. Recent Accounting Pronouncements

In May 2009, the FASB issued accounting guidance establishing the general standards of accounting for the disclosure of events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. In particular, this FASB guidance requires enhanced disclosures about (a) events or transactions that may occur for potential recognition or disclosure in the financial statements in the period after the balance sheet date, (b) circumstances under which an entity should recognize such events, and (c) date through which an entity has evaluated subsequent events, including the basis for that date, and whether that date represents the date the financial statements were issued or available to be issued. This FASB guidance is effective for financial statements issued for interim and annual periods ending after June 15, 2009. The adoption of this guidance did not have an impact on the Company's financial statements.

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

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities. The objective of the amendment is to improve financial reporting by enterprises involved with variable interest entities and to provide more relevant and reliable information to users of financial statements. The amendment requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The new requirements shall be effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009.

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

In January 2010, the FASB issued an amendment to the accounting guidance for fair value measurements that will provide for additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) the transfers between Levels 1, 2, and 3. This FASB guidance is effective for financial statement issued for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

NOTES TO THE FINANCIAL STATEMENTS

NOTE 2 - RATES AND REGULATORY

The Company's financial statements conform to GAAP, including the accounting principles for rate regulated entities with respect to its regulated operations. Because electricity rates have historically been based on a utility's costs, electric utilities are subject to certain accounting standards that are not generally applicable to other business enterprises. The current accounting guidance for rate-regulated entities recognizes the ability of regulators, through the rate-making process, to create future economic benefits and obligations affecting rate-regulated entities. Accordingly, the Company records regulatory assets (expenses deferred for future recovery from customers) and regulatory liabilities (revenues collected for future payment or return to customers) on its balance sheet.

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

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

Under settlement agreements approved by the appropriate commissions or FERC orders, the Company is permitted to recover costs associated with its former generating investments (nuclear and nonnuclear) and related contractual commitments that were not recovered through the sale of those investments (stranded costs). Stranded costs are recovered from the Company's affiliated former wholesale customers with whom it has settlement agreements through a CTC. The Company's affiliated former wholesale customers in turn recover the stranded cost charges through delivery charges to their distribution customers. The Company earns a return on equity ("ROE") of approximately 11% on stranded cost recovery. Most stranded costs will be fully recovered through CTCs by the end of 2010. The Company's stranded cost obligation related to the above-market cost of purchase power contracts and nuclear decommissioning costs are recovered through the CTC when the costs are actually incurred. The Company, under certain settlement agreements, earns incentives based on successful mitigation of its stranded costs through December 2009 and these incentives supplement the Company's ROE.

NEP is a Participating Transmission Owner ("PTO") in the New England Regional Transmission Organization ("RTO") which commenced operations effective February 1, 2005. The Independent System Operator for New England ("ISO-NE") has been authorized by FERC to exercise the operations and system planning functions required of RTOs and is the independent regional transmission provider under the ISO-NE Open Access Transmission Tariff ("ISO-NE OATT"). The ISO-NE OATT is designed to provide non-discriminatory open access transmission services over the transmission facilities of the PTOs and recover their revenue requirements. FERC issued a series of orders in 2004 and 2005 that approved the establishment of the RTO and resolved certain issues concerning the New England Transmission Owners ("NETOs"). Other ROE issues were set for hearing.

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

NEP and other NETOs participated in FERC proceedings to resolve outstanding ROE issues, including base ROE and the proposed 1.0% ROE incentive for new transmission investment. On October 31, 2006, FERC issued an order establishing the ROE for the NETOs, including NEP. In this order, FERC overturned the Administrative Law Judge's initial decision and approved, over the dissent of two Commissioners, the proposed 1.0% ROE adder for all new transmission investment approved through the regional system planning process as an incentive to build new transmission infrastructure. The resulting ROE varied depending on whether costs are recovered through RNS rates or local network service ("LNS") rates, and whether the costs are for existing or new facilities. For the locked-in period (February 2005 to October 2006), the resulting ROEs were 10.7% (including a 0.5% RTO participation adder) for recovery of existing transmission through RNS rates; 11.7% (including 0.5% and 1.0% adders) for new transmission costs recovered through RNS; and 10.2% (base ROE only) for LNS. For the prospective period beginning November 1, 2006, those ROEs increased to 11.4%, 12.4% and 10.9%, respectively, as a result of a FERC adjustment to reflect updated bond data. Overall, the ROEs approved by FERC represent an increase from 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, intervened in this proceeding. On January 29, 2010, the Court issued an order denying the petition and affirming the FERC's decision to award the 1.0% ROE adder for RTO-approved transmission projects placed in service by December 31, 2008.

On September 17, 2008, the Company, The Narragansett Electric Company, an NGUSA affiliate 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. The Narragansett Electric Company's share is estimated to be $474 million and the Company's share is estimated to be $160 million. Effective as of November 18, 2008, FERC granted for NEEWS (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Parties opposing the NEEWS incentives have sought rehearing of the FERC order.

NOTES TO THE FINANCIAL STATEMENTS

Under the terms of its FERC Electric Tariff No. 1, NEP operates the transmission facilities of its New England distribution affiliates as a single integrated system and reimburses its affiliates for the cost of those facilities, including a return. NEP's costs under Tariff No. 1 are then allocated among transmission customers in New England in accordance with the terms of the ISO-NE OATT. On December 30, 2009, NEP filed with FERC a proposed amendment to Tariff No.1 (1) to adjust depreciation rates and Postretirement Benefits Other than Pensions ("PBOPs") according to recent depreciation and actuarial studies updating such costs, and (2) to update rate formulas applicable to Massachusetts Electric Company. The result of the proposed rate change would be an overall rate decrease of $1.6 million. On March 29, 2010, FERC issued an order establishing hearing and settlement procedures for this filing and made the new rates effective January 1, 2010, subject to refund, pending the outcome of the proceeding. The Company cannot predict the outcome of this filing at this time.

As a result of applying the FASB guidance on rate-regulated enterprises, the Company has recorded net regulatory assets for the costs that are recoverable from customers through CTCs or through transmission rates.

The following table details regulatory assets and liabilities summarized in the Company's financial statements:

(in thousands of dollars)	**March 31, 2010**	March 31, 2009
Regulatory assets – current		
Purchased power payment obligations	**$ 2,521**	$ 4,035
Derivative instruments	**30,972**	29,483
Accrued Yankee nuclear decommissioning costs	**14,939**	14,846
Total current regulatory assets	**48,432**	48,364
Regulatory assets – non-current		
Purchased power payment obligations	**7,312**	9,636
Purchased power contracts bought-out		2,487
Derivative instruments	**160,538**	145,027
Accrued Yankee nuclear decommissioning costs	**66,665**	80,870
Pension and postretirement benefits	**94,049**	99,048
Regulatory tax asset	**16,953**	35,531
Other regulatory assets	**40,416**	50,384
Total regulatory assets non-current	**385,933**	422,983
Total regulatory assets	**434,365**	471,347
Regulatory liabilities		
CTC related liabilities	**(86,925)**	(99,302)
Cost of removal	**(24,764)**	(23,181)
Revaluation – pensions and PBOPs	**(24,235)**	(28,202)
Total regulatory liabilities	**(135,924)**	(150,685)
Net regulatory assets	**$ 298,441**	$ 320,662

Where applicable, the Company is earning a return on its regulatory assets under its filed rates. If the Company could no longer apply the deferred treatment of regulatory items, the resulting charge would be material to the Company's reported financial condition and results of operations.

NOTES TO THE FINANCIAL STATEMENTS

Purchased Power Payment Obligations: In conjunction with the Company's divestiture of its generating business, the Company accrued obligations related to certain purchase power contracts. The Company makes fixed monthly payments to the suppliers.

Purchased Power Contracts Bought-out: In conjunction with the Company's divestiture of its generating business, 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.

Derivative Instrument: Physical Derivatives–Not Receiving Hedge Accounting (Regulated Utilities)
As a result of the USGen bankruptcy settlement agreement ("Bankruptcy Settlement"), the Company resumed the performance and payment obligations under power supply contracts that had been transferred to USGen when the Company divested its generating business. These power supply contracts have been determined to be derivative instruments (see Note 8-Derivative contracts).

Accrued Yankee Nuclear Decommissioning Costs: This regulatory asset represents the estimated future decommissioning billings from a group of three nuclear generating utilities consisting of Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and Maine Yankee Atomic Power Company ("Maine Yankee") (together, "the Yankees"). Under settlement agreements, the Company is permitted to recover prudently incurred decommissioning costs through CTC's. For a discussion of decommissioning nuclear units see Note 11-Commitments and Contingencies.

Other Regulatory Assets: Other regulatory assets largely consist of unrecovered costs associated with divested fixed assets that are being recovered through the CTC.

CTC Related Liabilities: CTC related liabilities consist of obligations to customers that resulted from the sale of certain stranded assets. These amounts are being refunded to customers as determined under various rate agreements.

Revaluation - Pensions and Other Postretirement Employee Benefits: As a result of the fiscal year 2000 merger of the Company with National Grid USA and the fiscal year 2001 acquisition of Montaup Electric Co., the Company revalued its pension and other postretirement benefit plans in accordance with the FASB accounting guidance related to employers accounting for pensions and PBOPs which resulted in the recognition of previously unrecognized net gains in these benefit plans. The recognition of these gains was offset on the Balance Sheet by the establishment of a regulatory liability which is being passed back to customers over a 15 year period.

NOTE 3 - EMPLOYEE BENEFITS

Summary: The Company participates in a non-contributory defined benefit pension plan and a postretirement benefits other than pensions ("PBOP") plan (the "Plans"). The Plans cover substantially all employees of the Company and certain other NGUSA subsidiaries.

The pension plan is a non-contributory, tax-qualified defined benefit plan which provides all employees with a minimum retirement benefit. Under the pension plan, a participant's retirement benefit is computed using formulas based on percentages of highest average compensation computed over five consecutive years. The compensation covered by the pension plan includes salary, bonus and incentive

share awards. Non-union employees hired after July 15, 2002 participate under a non-contributory defined benefit cash balance design.

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

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

Pension Benefits: The Company participates in the pension plans with certain other NGUSA subsidiaries. Pension plan assets are commingled and cannot be allocated to an individual company. Pension costs are allocated to the Company. At March 31, 2010 the pension plans have a net underfunded obligation of $420.7 million. The Company's net periodic pension cost for 2010 was approximately $3.2 million.

Postretirement Benefits Other Than Pension: The Company participates in the PBOP plans with certain other NGUSA subsidiaries. PBOP costs are allocated to the Company. The PBOP plans have a net underfunded obligation of $477.3 million and $476.8 as of March 31, 2010 and 2009, respectively. The Company's net periodic postretirement benefit cost for 2010 and 2009 was approximately $1.7 million and $0.6 million, respectively.

Health Care Reform Act: In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 became law. These laws included provisions which resulted in the repeal, with effect from 2012, of the deduction for federal income tax purposes of the portion of the cost of an employer's retiree prescription drug coverage for which the employer received a benefit under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The consequential reduction in the deferred tax asset balance resulted in a net charge to the income statement of approximately $1.4 million partially offset by the reversal of a regulatory liability of $0.9 million (or $0.5 million after tax), which reduced the impact to $0.9 million. As this change will be reflected in the rates charged by the Company to its customers, the net impact in the income statement after reflecting accrued revenues and the associated taxes was zero.

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. Of the 560 employees enrolled in the VERO, none were the Company's employees. Employees enrolled in the early retirement program will retire by October 1, 2010. The Company's share of the cost of the VERO program is expected to be $5.2 million, which consists of VERO costs allocated from affiliates. The Company recorded $1.1 million and $2.4 million of expense for the years ended March 31, 2010 and 2009, respectively. The remaining costs will be expensed through October 1, 2010 as program participants retire.

During the year ending March 31, 2010, an additional VERO package was offered to 30 union employees in connection with National Grid plc's acquisition of KeySpan to further the effort to achieve necessary staff reduction through voluntary means. Of the 30 eligible employees, 28 enrolled in the VERO and were all employees of one affiliate of the Company. Employees enrolled in the early retirement program retired between October 1, 2008 and December 1, 2009. The Company recorded $0.2 million of allocated costs associated with this VERO package.

NOTES TO THE FINANCIAL STATEMENTS

NOTE 4 - DEBT

Short-term Debt: The Company has regulatory approval to issue up to $375 million of short-term debt. At March 31, 2010 and 2009, the Company had no short-term debt outstanding.

At March 31, 2010 and 2009, the Company had lines of credit and standby bond purchase facilities with banks totaling $450 million and $440 million, respectively, which is available to provide liquidity support for $410 million of the Company's long-term bonds in tax-exempt commercial paper mode, and

for other corporate purposes. The previous agreements with banks that provided the Company's line of credit and standby bond purchase facility expired and new agreements were executed in November 2009. Lines of credit totaling $75 million expire on November 23, 2010, and a standby bond purchase agreement in the amount of $375 million expires on November 30, 2011. There were no borrowings under these agreements at March 31, 2010.

Long-term Debt: At March 31, 2010, the Company had outstanding $410 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode which were issued through the Business Finance Authority of the State of New Hampshire, the Massachusetts Industrial Finance Authority, and the Connecticut Development Authority. Interest rates ranged from 0.60% to 1.99% for the year ended March 31, 2010.

The aggregate maturities of long-term debt for the five years subsequent to March 31, 2010 and thereafter are approximately:

(in thousands of dollars)	
March 31	**Amount**
2011	$ -
2012	-
2013	-
2014	-
2015	38
Thereafter	410,312
Total	$ 410,350

At March 31, 2010, interest rates on the Company's variable rate long-term bonds ranged from 0.60% to 0.90%. There are no payments or sinking fund requirements due in 2011 through 2015.

NOTE 5 - OTHER INVESTMENTS

Yankee Nuclear Power Companies: At March 31, 2010, the Company had minority interests in the Yankee Atomic Electric Company ("Yankees"), which own 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. These ownership interests are accounted for using the equity method. The Company has power contracts with each of the Yankees that require the Company to pay an amount equal to its share of total fixed and operating costs of the plant plus a return on equity. The Company's share of the expenses of the Yankees is accounted for in "Purchased electric energy" on the Statements of Income.

The following table summarizes financial information furnished by the Yankees:

New England Power Company

(in thousands of dollars)	Fiscal year ended December 2010		2009	
Operating revenue	**$**	**57,788**	$	82,897
Net income	**$**	**706**	$	1,095
Company's equity in net income	**$**	**142**	$	243
Net plant	**$**	**1,625**	$	1,625
Other assets	**$**	**942,338**	$	953,949
Liabilities and debt	**$**	**(936,975)**	$	(938,920)
Net assets	**$**	**6,988**	$	16,654
Company's equity in net assets	**$**	**1,710**	$	3,587

NOTE 6 - PROPERTY, PLANT AND EQUIPMENT

The following table summarizes the composition of the Company's property, plant and equipment balance as of March 31, 2010 and 2009:

(in thousand of dollars)	Plant and Machinery	Land and Buildings	Vehicles and Equipment	Assets in Construction	Total
Balance at March 31, 2008	$ 1,107,167	$ 57,328	$ 168	$ 50,392	$ 1,215,055
Additions	-	-	-	146,746	146,746
Disposals	(36,309)	(1,989)	-	-	(38,298)
Reclassifications	153,382	(4,846)	-	(66,961)	81,575
Balance at March 31, 2009	1,224,240	50,493	168	130,177	1,405,078
Accumulated depreciation at March 31, 2009	(273,527)	(5,378)	-	-	(278,905)
Net book value at March 31, 2009	$ 950,713	$ 45,115	$ 168	$ 130,177	$ 1,126,172
Balance at March 31, 2009	$ 1,224,240	$ 50,493	$ -	$ 130,177	$ 1,405,078
Additions	-	-	-	143,108	143,108
Disposals	(6,285)	(14)	-	-	(6,299)
Reclassifications	191,456	-	-	(191,923)	(467)
Total at March, 31, 2010	$ 1,409,411	$ 50,479	$ 168	$ 81,362	$ 1,541,420
Accumulated depreciation at March 31, 2010	(291,155)	(5,696)	-		(296,851)
Net book value at March 31, 2010	$ 1,118,256	$ 44,783	$ 168	$ 81,362	$ 1,244,569

Allowance For Funds Used During Construction ("AFUDC"): The Company capitalizes AFUDC as part of construction costs. AFUDC represents an allowance for the cost of funds used to finance construction. AFUDC is capitalized in "utility plant" with offsetting cash credits to "other interest" for the debt component and to "other income, net" for the equity component. This method is in accordance with an established rate-making practice under which a utility is 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. The composite AFUDC rates were 7.7% and 6.9% for the years ended March 31, 2010 and 2009, respectively.

NOTES TO THE FINANCIAL STATEMENTS

The amounts of AFUDC credits were recorded as follows:

(in thousands of dollars)		Years ended March 31, 2010		2009
Other income	**$**	**3,212**	$	3,661
Interest	**$**	**189**	$	300

Depreciation and Amortization: The depreciation expense included in the Statements of Income is composed of the following:

(in thousands of dollars)		Years ended March 31, 2010		2009
Amortization of stranded costs:				
Purchased power contract buyouts	**$**	**-**	**$**	**-**
Regulatory assets covered by contract termination charges		**8,836**		9,683
Total amortization of stranded costs	**$**	**8,836**	$	9,683
Other depreciation and amortization:				
Depreciation - transmission related	**$**	**30,359**	$	27,268
Depreciation - all other		**46**		41
Amortization – transmission related		**-**		91
Total other depreciation and amortization expense	**$**	**30,405**	$	27,400

Depreciation: Depreciation is provided annually on a straight-line basis. The provisions for depreciation, as a percentage of weighted average depreciable property, and the weighted average service life, in years, for the years ended March 31 are presented in the table below:

	2010		2009	
	Provision	**Average service life**	Provision	Average service life
Asset Category:				
Electric	**2.31%**	**43**	2.30%	43

Amortization: Amortization of purchased power contracts and regulatory assets covered by CTC is provided over the recovery period as allowed in the applicable regulatory agreement.

NOTES TO THE FINANCIAL STATEMENTS

NOTE 7 - INCOME TAXES

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 Statements of income and the computed amount at the statutory tax rate:

		Tax Year Ended March 31,		
(in thousands of dollars)		**2010**		2009
Components of federal and state income taxes:				
Current tax expense (benefit):				
Federal	**$**	**(23,661)**	$	26,488
State		**(2,674)**		5,513
Total current tax expense		**(26,335)**		32,001
Deferred tax expense:				
Federal	**$**	**72,459**	$	19,212
State		**10,050**		2,405
Investment tax credits (1)		**(404)**		(406)
Total deferred tax expense		**82,105**		21,211
Total income tax expense	**$**	**55,770**	$	53,212

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

Income tax expense for the fiscal year ending 2010 and 2009 varied from the amount computed by applying the statutory rate to income before income taxes. A reconciliation between the expected federal income tax expense using the federal statutory rate of 35% to the Company's actual income tax expense for the fiscal year ending 2010 and 2009 is presented in the following table.

		Fiscal Year Ended March 31,		
(in thousands of dollars)		**2010**		2009
Computed tax	**$**	**48,295**	$	50,219
Increase (reduction) including those attributable to flow-through of certain tax adjustments:				
State income taxes, net of federal income tax benefit		**4,794**		4,781
Adjustments to federal and state prior year balances		**1,195**		
Allowance for equity funds used during construction		**(1,124)**		
Medicare subsidy, including Patient Protection & Affordable Care Act effect, net		**616**		(153)
Investment tax credit		**(404)**		(264)
Provision to return adjustments		**(159)**		(48)
Inter-company tax allocation		**(2,115)**		(3,348)
Rate recovery of deficiency in deferred tax reserves		**3,642**		3,512
Other items, net		**1,030**		(1,487)
Total	**$**	**7,475**	$	2,993
Federal and state income taxes	**$**	**55,770**	$	53,212

New England Power Company

NOTES TO THE FINANCIAL STATEMENTS

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

(in thousands of dollars)		**March 31, 2010**		March 31, 2009
Deferred tax asset related to regulatory liabilities	**$**	**-**	$	72,575
Reserve - Environmental		**-**		30,142
Pensions, OPEB and other employee benefits		**10,384**		18,728
Reserve - Nuclear and decommisioning		**29,379**		-
Future federal benefit on state taxes		**13,177**		3,613
Other items		**3,901**		22,455
Total deferred tax assets[1]		**56,841**		147,513
Property-related differences		**(249,633)**		(214,791)
Regulatory tax assets				(69,414)
Regulatory assets-other		**(36,331)**		
Regulatory assets - Pension and OPEB		**(4,166)**		(27,121)
Other items		**(7,939)**		(13,673)
Total deferred tax liabilities		**(298,069)**		(324,999)
Net accumulated deferred income tax liability		**(241,228)**		(177,486)
Current portion (net deferred tax liability)		**(2,497)**		(3,434)
Net accumulated deferred income tax liability (non-current)	**$**	**(238,731)**	$	(174,052)
Accumulated unamortized investment tax credits	**$**	**(5,375)**	$	(5,778)

[1] There were no valuation allowances for deferred tax assets at March 31, 2010 or 2009.

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

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

With the application of this FASB guidance, as of March 31, 2010 and 2009, the Company’s unrecognized tax benefits totaled $27.1 million and $0.2 million, respectively, of which $2.8 million and $0.2 million would affect the effective tax rate, if recognized.

NOTES TO THE FINANCIAL STATEMENTS

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31.

Reconciliation of Unrecognized Tax Benefits	**Year ended March 31,**	
(in thousands of dollars)	**2010**	2009
Beginning balance	**$ 215**	$ 885
Gross increases (decreases) related to prior period		157
Gross increases (decreases) related to current period	**27,249**	-
Settlements with tax authorities	**(335)**	(827)
Reductions due to lapse of statute of limitations	**-**	0
Ending balance	**$ 27,129**	$ 215

As of March 31, 2010 and 2009, the Company has accrued interest related to unrecognized tax benefits of $0.6 and $1.9 million, respectively. During the fiscal years ended March 31, 2010 and 2009, the Company recorded interest expense of $0.03 and $0.08 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in interest expense or interest income and related penalties, if applicable, in operating expenses. No penalties were recognized during the fiscal years ended March 31, 2010 and 2009.

The Company is a member of a federal consolidated return with its parent, NGHI. 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 through March 31, 2004.

On July 2, 2008, the state of Massachusetts changed the state filing requirements that eliminate the previous separate reporting filing rules and implemented a unitary group filing requirement. The new combined reporting rules are effective for tax years beginning on or after January 1, 2009. This change does not have a material effect on the 2010 or 2009 financial statements.

NOTE 8 - DERIVATIVE CONTRACTS

Physical Derivatives: As a result of the USGen bankruptcy settlement agreement ("Bankruptcy Settlement"), New England Power resumed the performance and payment obligations under power supply contracts that had been transferred to USGen when the Company divested its generating business.
The fair value of these derivative instruments at March 31, 2010 was a liability of $191.5 million.

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

The following are commodity volumes associated with those derivative contracts:

As of March 31, 2010		
(in thousands)		
Physical	Electric (Mwhs)	3,883
Total	**Electric (Mwhs)**	**3,883**

In March 2008, the FASB issued the accounting guidance relating to disclosure requirements about derivative instruments and hedging 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 guidance 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 this guidance and has been applied to our financial reports for the year ending March 31, 2010.

The following are balance sheet, income statement tables for various commodities.

Fair Values of Derivative Instruments - Balance Sheet

	Asset Derivatives			Liability Derivatives	
(in thousands of dollars)	**March 31, 2010**	March 31, 2009		**March 31, 2010**	March 31, 2009
Regulated contracts					
Electric Contracts:					
Electric Purchase Contract - Current Asset	**$ 508**	$ -	Electric Purchase Contract - Current Liability	**$ (31,480)**	$ (29,483)
Electric Purchase Contract - Deferred Asset	**604**	-	Electric Purchase Contract - Deferred Liability	**(161,142)**	(145,027)
Total derivatives not designated as hedging instruments	**1,112**	-		**(192,622)**	(174,510)
Total Derivatives	**$ 1,112**	$ -		**$ (192,622)**	$ (174,510)

Fair Values of Derivative Instruments - Statements of Income

(in thousands of dollars)			
Derivatives Not Designated as Hedging Instrument	YTD Movement	**March 31, 2010**	March 31, 2009
Regulated Contracts:			
Electric Purchase Contracts - Regulatory Asset	(17,000)	**(191,510)**	(174,510)
Electrict Purchase Contract - Regulatory Liability			
Total	(17,000)	**(191,510)**	(174,510)

Movements in the fair value of regulated contracts are recorded in the Balance Sheets. Movements in the fair value of non-regulated contracts are recorded in the Statements of Income.

NOTE 9 - FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date - exit price. The determination of the fair value incorporates various factors which include not only the credit standing of the counterparties involved but also the impact of the Company's nonperformance risk on its liabilities.

The following table presents assets and liabilities measured and recorded at fair value on the Company's Balance Sheet on a recurring basis and their level within the fair value hierarchy at March 31, 2010:

Fair Value Measurement Level Summary Table

(in thousands of dollars)	Level 1	Level 2	Level 3	Total
Assets				
Derivative contracts	$ -	$ -	$ 1,112	1,112
Available for sale securities	2,695	3,578	-	6,273
Total assets	2,695	3,578	1,112	7,385
Liabilities				
Derivative contracts	-	-	(192,622)	(192,622)
Total liabilities	-	-	(192,622)	(192,622)
Net asset/(liabilities) balance	$ 2,695	$ 3,578	$ (191,510)	$ (185,237)

Derivative contracts — The Company enters into a variety of derivative instruments to include both exchange traded and OTC gas forwards, options and swaps.

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

The Company's level 2 fair value derivative instruments primarily consist of power OTC swaps and forward physical gas deals where market data for pricing inputs is observable. Level 2 pricing inputs are obtained from NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from Intercontinental Exchange. Level 2 derivative instruments may utilize discounting based on quoted interest rate curve as well as have liquidity reserve calculated based on bid/ask spread. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 0.95 or higher.

The Company's level 3 fair value derivative instruments primarily consist of our physical 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 Financial Engineering Associates (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.

The following table presents the fair value reconciliation of level 3 assets and liabilities measured at fair value on a recurring basis during the year ended March 31, 2010:

(in millions of dollars)	
Balance at March 31, 2009	$ (174,510)
Transfers into Level 3	-
Transfers out of Level 3	-
Total gains and losses:	
included in earnings (or changes in net assets)	-
included in other comprehensive income	-
included in regulatory assets and liabilities	(17,000)
Purchases	
Sales	
Balance at March 31, 2010	(191,510)
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, 2010	$ -

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

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

Long term debt — Long term debt is based on quoted market prices where available or calculated prices based on the remaining cash flows of the underlying bond discounted at the Company's incremental borrowing rate. The Company's Balance Sheet reflects the long term debt at carrying value. The fair value of this debt at March 31, 2010 is $410.3 million.

NOTE 10 - ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The following table presents the components of accumulated other comprehensive income on the Company's Balance Sheet:

(in thousands of dollars)		Total Accumulated Other Comprehensive Income/(Loss)
Ending balance, March 31, 2009	$	(338)
Other comprehensive income/(loss), net of tax:		
Unrealized gains on securities, net of taxes of $389		991
Reclassification adjustment for gain included in net income, net of taxes of $76		(388)
Ending balance, March 31, 2010	$	265

NOTE 11 - COMMITMENTS AND CONTINGENCIES

Decommissioning Nuclear Units:

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 DOE of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. Future estimated billing which are included in miscellaneous current/accrued liabilities and other deferred credits are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2010				Future Estimated Billings to the Company	
Unit	%		Amount	Date Retired		Amount
Yankee Atomic	34.5	$	546	Feb 1992	$	19,255
Connecticut Yankee	19.5		577	Dec 1996		51,391
Maine Yankee	24.0		587	Aug 1997		10,958

The Company recorded a 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 the Company. The Company's share of the decommissioning costs is accounted for in "Purchased electric energy" on the income statement. Under settlement agreements, the Company is permitted to recover prudently incurred decommissioning costs through CTCs.

The Yankees are periodically required to file rate cases for FERC approval, which present the Yankees' estimated future decommissioning costs. The Yankees are currently collecting decommissioning and other costs under FERC Orders issued in their respective rate cases.

Future estimated billings from the Yankees are based on cost estimates. These estimates include the projected costs of groundwater monitoring, security, liability and property insurance and other costs. They also include costs for interim spent fuel storage facilities, which the Yankees have constructed during litigation they brought to enforce the DOE's obligation to remove the fuel as required by the Nuclear Waste Policy Act of 1982. Following a trial at the U.S. Court of Federal Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies approximately $143 million for spent fuel storage costs that had been incurred through 2001 and 2002. The Yankees had requested $176.3 million. On December 4, 2006, the DOE filed a notice of appeal with the U. S. Court of Appeals for the Federal Circuit. The Court of Appeals rendered an opinion generally supporting the trial court's decision and has remanded the matter to the trial court for further proceedings. A Claims Court trial in the remanded cases was held in August, 2009. A decision has not yet been issued. If the Yankees are successful in the litigation, the damages received by the Yankees, net of litigation expenses and taxes, will be applied to reduce the decommissioning and other costs collected from their purchasers including the Company. On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2001 and 2002. The parties are negotiating a discovery schedule in that litigation. The DOE has severely curtailed budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and taken actions designed to prevent its construction and appointed a Blue Ribbon Commission charged with advising it regarding alternatives to disposal at Yucca Mountain. As a result, it is impossible to predict when the DOE will fulfill its obligation to take possession of the Yankees' spent fuel. The decommissioning costs that are actually incurred by the Yankees may exceed the estimated amounts, perhaps substantially.

Connecticut Yankee Rate Filing:
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 table above. 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 earn a return on more than $10 million in equity.

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.

On April 6, 2010, Connecticut Yankee asked FERC to waive a requirement of its wholesale rate schedule that otherwise would require an upward adjustment of the decommissioning charges to NEP and other customers effective, May 1, 2010. Connecticut Yankee stated that it would reflect the impact of the increase, together with other factors affecting decommissioning charges, in a revised schedule of such charges that it is required by the 2006 settlement to submit, before the end of 2010. On May 5, 2010, FERC issued an order granting the requested waiver.

NOTES TO THE FINANCIAL STATEMENTS

Maine Yankee Rate Filing:

Maine Yankee submitted a Section 205 rate filing to FERC on August 1, 2008. The sole purpose of this filing is 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.

Hydro Quebec Interconnection:
Three affiliates of NGUSA were created to construct and operate transmission facilities to transmit power from Hydro Quebec (a generation facility in Quebec, Canada) to New England. Under the financial and organizational agreements (the "Support Agreements") entered into at the time these facilities were constructed, the Company agreed to guarantee a portion of the project debt. At December 31, 2009, the Company had guaranteed approximately $8.1 million of project debt with terms through 2015. Costs associated with these Support Agreements are recoverable from the Company's customers through CTCs.

Town of Norwood Dispute:
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.

FERC 2006 Proceeding: 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 grounds that it goes beyond FERC's authority to award retroactive relief under Section 206 of the Federal Power Act, and violates the filed rate doctrine. On July 16, 2008, the First Circuit again remanded the case to FERC for further consideration of exactly when the reduced interest rate should apply to calculate the payment due from Norwood. On January 15, 2009, FERC issued an order on remand leaving, in effect the tariff's 1.5% interest rate applicable to Norwood's unpaid monthly CTC bills for the period from the 1998 inception of the CTC through February 20, 2004 and from May 22, 2004 through June 29, 2006. Interest on unpaid CTC bills for the remaining periods is to be calculated in accordance with the interest rates set by Section 35.19a of the Commission's regulations. On February 13, 2009 Norwood filed a rehearing request at FERC seeking an expansion of the time period in which the reduced interest rates are applicable, and seeking an order directing that the interest rates not be subject to compounding.
NOTES TO THE FINANCIAL STATEMENTS

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

State Collection Action: In 1998, the Company 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. In September 2009, the state collection action and companion federal litigation were discontinued with prejudice.

Long-term Contracts for the Purchase of Electric Power:
The Company has 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, 2010, are summarized in the table below.

(In thousands)

Year	**Estimated Payments**
2011	$ 62,746
2012	61,955
2013	59,806
2014	59,640
Thereafter	163,644
Total	$ 407,791

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

Hazardous Waste:
The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations. Like many other industrial companies, the Company generates hazardous wastes. 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 activities were lawful when they occurred.

The Company is currently conducting a program to investigate and remediate, as necessary to meet current environmental standards, certain properties which the Company has learned may be contaminated with industrial waste sites as to which it may be determined that the Company has contributed. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company believes that obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position.

NOTES TO THE FINANCIAL STATEMENTS

Plant Expenditures:
Generally, construction expenditure levels are consistent from year to year. However, the Company has undertaken a Reliability Enhancement Program to improve performance and reliability.

Cost of Removal and Asset Retirement Obligation:
The Company adheres to the current accounting guidance relating to asset retirement obligations associated with tangible long-lived assets. The Company does not have any material asset retirement obligations arising from legal obligations as defined under this guidance.

However, under the Company's current and prior rate plans, it has collected through rates an implied cost of removal for its plant assets. This cost of removal collected from customers differs from the FASB guidance definition of an asset retirement obligation in that these collections are for costs to remove an asset when it is no longer deemed usable (i.e. broken or obsolete) and not necessarily from a legal obligation. The Company estimates it has collected over time approximately $24.8 million and $23.2 million for cost of removal through March 31, 2010 and 2009, respectively.

In March 2005, the FASB issued an interpretation of its earlier published guidance related to the accounting for asset retirement obligations which was adopted by the Company for the fiscal year ended March 31, 2006. This interpretation clarifies that the term "conditional asset retirement obligation" used in the earlier guidance refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. The Company continues to monitor such contingencies, which do not have a material impact on the Company's results of operations or its financial position for the years ended March 31, 2010 and 2009.

NOTE 12 - RELATED PARTY TRANSACTIONS

Money Pool: The Company participates with National Grid and its affiliates in a system money pool. The money pool is administered by a National Grid service company as the agent for the participants. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowings from the money pool bear interest at the higher of (i) the monthly average of the rate for high-grade, 30-day commercial paper sold through dealers by major corporations as published in The Wall Street Journal, or (ii) the monthly average of the rate then available to money pool depositors from an eligible investment in readily marketable money market funds or the existing short-term investment accounts maintained by money pool depositors or the NGUSA service company during the period in question. In the event neither rate is one that is permissible for a transaction because of constraints imposed by the state regulatory commission having jurisdiction over a utility participating in the transaction, the rate is adjusted to a permissible rate as determined under the requirements of the state regulatory commission. 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 money pool at any time without prior notice. The Company had accounts receivable from money pool of $144.7 million and $278.6 million at March 31, 2010 and 2009, respectively.

The average interest rate for the money pool was 0.27% and 1.96% for the years ended March 31, 2010 and 2009, respectively.

Accounts Receivable from Affiliates: Additionally, the Company engages in various transactions with National Grid and its affiliates. The Company provides transmission of electricity in wholesale

quantities to its affiliates. In addition, certain activities and costs, such as executive and administrative, financial (including accounting, auditing, risk management, tax and treasury/finance) human resources, information technology, legal and strategic planning are shared between the companies and allocated to each company appropriately. In addition, the Company has a tax sharing agreement with NGHI in filing consolidated tax returns. The Company's share of the tax liability is allocated resulting in a payment to or from the Company (See Note 7 – Income taxes on filing consolidated tax returns). At March 31, 2010 and 2009, the Company had a receivable balance from (net of payables to) affiliates of $24.7 million and $9.4 million, respectively, for these services.

Service Company Charges: Certain costs are allocated to the Company from NGUSA's service companies on a cost basis. These costs, including both operating and capital costs, amounted to approximately $74.2 million and $65.4 million for the years ended March 31, 2010 and 2009, respectively.

Parent Company Charges. For the year ended March 31, 2010, NGUSA received charges from Commercial Holdings Limited (an affiliated company in the UK) for certain corporate and administrative services provided by the Corporate functions of National Grid plc to its US subsidiaries.

These charges, which are recorded on the books of NGUSA, have not been reflected on these financial statements. Were these amounts allocated to this subsidiary, the effect on net income would be approximately $0.7 million before taxes, and $0.4 million, after taxes.

NOTE 13. CUMULATIVE PREFERRED STOCK

A summary of cumulative preferred stock at March 31 is as follows (in thousands of dollars except for share data):

	Shares Outstanding		Amount		Dividends Declared	
(in thousands of dollars)	**2010**	2009	**2010**	2009	**2010**	2009
$100 par value 6.00% Series (a)	**11,117**	11,117	**$1,112**	$1,112	**$67**	$67

(a) Noncallable.

There are no mandatory redemption provisions on the Company's cumulative preferred stock.