National Grid USA / Annual Report

Fiscal year ended March 31, 2005

nationalgrid

Cautionary Statement
This Annual Report of National Grid USA contains certain statements that are neither reported financial results nor other historical information. These statements are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Throughout this report, forward-looking statements can be identified by the words or phrases “will likely result”, “are expected to”, “will continue”, “is anticipated”, “estimated”, “projected”, “believe”, “hopes”, or similar expressions. Because these forward-looking statements are subject to assumptions, risks and uncertainties, actual future results may differ materially from those expressed in or implied by such statements.

Many of these assumptions, risks and uncertainties relate to factors that are beyond management’s ability to control or estimate precisely, such as delays in obtaining or adverse conditions contained in regulatory approvals; competition and industry restructuring; changes in economic conditions; adverse changes in electric load; currency fluctuations; changes in interest and tax rates; changes in energy market prices; federal and state regulatory developments and changes in law, regulations or regulatory policies; timing and adequacy of rate relief, including failure to recover costs currently deferred under the provisions Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation”, as amended; changes in accounting rules and interpretations which may have an adverse impact on financial position and results of operations; technological developments; or the failure to retain key management.

Other factors that could cause actual results to differ materially from those described in this document include the ability to continue to integrate the businesses acquired by or merged with the Company or to realize expected synergies from such integrations; the failure to achieve reductions in costs or to achieve operational efficiencies; unseasonable weather affecting demand for electricity and gas; the regulatory treatment of pension costs; and any adverse consequences arising from outages on or otherwise affecting energy networks which we own or operate.

Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Neither National Grid plc nor National Grid USA undertakes any obligation to revise any statements in this report to reflect events or circumstances after the date of this report.

TABLE OF CONTENTS

THE COMPANY

The following is only a summary and is not intended to be a comprehensive description of National Grid USA (the Company) or the activities of its subsidiaries. For further information about National Grid USA, please see National Grid Transco's Annual Report and Accounts 2004/05, available at www.nationalgrid.com, or as part of National Grid Transco's Annual Report on Form 20-F for fiscal year ended March 31, 2005 and other reports filed with the US Securities and Exchange Commission (the SEC); New England Power Company's Annual Report on Form 10-K for fiscal year ended March 31, 2005 and other SEC filings; and Niagara Mohawk Power Corporation's Annual Report on Form 10-K for fiscal year ended March 31, 2005 and other SEC filings. These documents are not incorporated by reference.

National Grid USA is a Delaware corporation and an indirect wholly owned subsidiary of National Grid plc (National Grid). National Grid plc, (formerly National Grid Transco plc), is an international network utility company with electricity and gas transmission and distribution interests in the UK and the US.

Prior to its acquisition by National Grid in 2000, National Grid USA was known as New England Electric System. The Company expanded its operations with the acquisitions of Eastern Utilities Associates in 2000 and Niagara Mohawk Holdings, Inc. in 2002.

National Grid USA is the holding company for National Grid's US operations. The Company's reportable segments are electricity-transmission, electricity-distribution including the sub-segment stranded cost recoveries and gas-distribution with the remainder of its activities reported under "Other". The principal operating companies that perform these activities are summarized in the table below.

Company and service area	Calendar 2005 Customer Base (approximately)	Fiscal 2005 Financial information (before intercompany eliminations) ($'s in 000's)	
Niagara Mohawk Power Corporation Electricity & Gas distribution and Electricity transmission company serving central, northern and eastern New York	1.6 million electric customers in 669 cities and towns 565,000 gas customers in 197 cities and towns	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 3,925,171 500,694 260,321 12,518,362
Massachusetts Electric Company Electricity distribution company serving customers throughout Massachusetts	1.2 million customers in 171 cities and towns	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 1,964,091 122,125 98,521 3,286,625
The Narragansett Electric Company Electricity distribution and transmission company serving the state of Rhode Island	476,000 customers in 38 cities and towns	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 816,024 79,049 68,042 1,686,713
Granite State Electric Company Electricity distribution company serving Southern New Hampshire and portions of the Connecticut River Valley	40,000 customers in 21 communities	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 76,572 6,139 4,826 101,382

Company and service area	Calendar 2005 Customer Base (approximately)	Fiscal 2005 Financial information (before intercompany eliminations) ($'s in 000's)		
Nantucket Electric Company Electricity distribution company serving Nantucket Island off Massachusetts	12,000 customers on Nantucket Island	Operating Revenue: Operating Profit: Net Income: Total Assets:	$	18,150 1,777 916 70,379
New England Power Company Electricity transmission company serving Massachusetts, Rhode Island and New Hampshire	Principally the New England electricity distribution affiliates: Massachusetts Electric Company, The Narragansett Electric Company, Granite State Electric Company and Nantucket Electric Company	Operating Revenue: Operating Profit: Net Income: Total Assets:	$	458,261 84,494 76,808 2,675,908
GridAmerica LLC (1) Electricity transmission grid management serving utilities in Ohio, Indiana, Missouri, and Illinois	Manages the transmission assets of three participating utilities, in coordination with the Midwest ISO	Operating Revenue: Operating Profit: Net Income: Total Assets:	$	11,410 1,598 1,430 2,478
National Grid Communications, Inc. and NEES Communications, Inc. Telecommunications infrastructure companies operating in New England and New York	Provider of telecommunications and wireless infrastructure and services in New England and New York	Operating Revenue: Operating Profit: Net Income: Total Assets:	$	24,920 3,543 3,504 254,850

(1) *During April 2005, Ameren notified the Company's electricity transmission business and its fellow GridAmerica participants that it will withdraw from GridAmerica effective November 1, 2005. Together with FirstEnergy and Northern Indiana Public Service Company, the Company evaluated GridAmerica's viability given the current industry environment, their respective long-term corporate strategies and Ameren's departure, and ultimately agreed to cease GridAmerica operations also effective November 1, 2005.*

INCENTIVE RETURNS UNDER RATE PLANS

We recover our costs of providing electricity and gas distribution, stranded cost recovery and electricity transmission service under rates approved by the applicable regulators. The rates are set based on historical or forecasted costs, and we earn a return on our assets, including a return on the "stranded costs" associated with the divestiture of our generating assets under deregulation and we may earn additional amounts to the extent we generate additional efficiencies. Commodity costs are passed through directly to customers. We are also subject to service quality standards in New York, Massachusetts and Rhode Island with respect to reliability and other aspects of customer service. We are subject to penalties if we fail to meet certain targets and, in Massachusetts, we can also earn incentives for outstanding performance.

Under long-term rate plans in New York, Massachusetts and Rhode Island, the Company's distribution subsidiaries are allowed by state regulators the opportunity to earn and retain certain amounts in excess of traditional regulatory allowed returns. These incentive returns and shared savings allowances are designed to provide the subsidiaries with an opportunity to use efficiency gains following their mergers to more than offset the costs of completing those mergers.

Niagara Mohawk's electricity delivery rates are governed by a long-term rate plan that became effective on January 31, 2002, the closing of the merger. Under the plan, rates were designed so that Niagara Mohawk may earn a threshold return on equity (ROE) for its electricity distribution business of 10.6% after reflecting its share of savings related to the acquisition. Niagara Mohawk is also allowed to earn up to 12.0% if certain customer education targets are met, and half of any earnings in excess of that amount. The ROE is calculated cumulatively from inception to December 31, 2005 and on a two-year rolling basis thereafter. The earnings calculation used to determine the regulated returns excludes half of the synergy savings, net of the cost to achieve them, that were assumed in the rate plan. This exclusion effectively offers Niagara Mohawk the potential to achieve a return in excess of the regulatory allowed return of 10.6%.

Niagara Mohawk collects transmission business revenues under several Federal Energy Regulatory Commission (FERC) rate schedules and state energy delivery rates. Total transmission business revenues are determined by the state-approved 10-year rate plan.

Under Niagara Mohawk's rate plan, gas delivery rates were frozen until the end of the 2004 calendar year. Niagara Mohawk now has the right to request an increase at any time, if needed. Under the plan, rates were designed so that Niagara Mohawk may earn a threshold ROE of up to 10.6%. Niagara Mohawk is also allowed to earn up to 12.0% if certain customer migration and education goals are met, and is required to share earnings above this threshold with customers.

Under Massachusetts Electric's long-term rate plan, there is no cap on earnings and no earnings sharing mechanism until 2010. From May 2000 until February 2005, rates were frozen. In March 2005, a settlement credit in the company's rates expired, which represents an increase of $10 million in pre-tax income through February 2006. From March 2006, rates will be adjusted each March until 2009 by the annual percentage change in average unbundled electricity distribution rates in the northeastern US. In 2010, actual earned savings will be determined and the company will be allowed to retain 100% of annual earned savings up to $70 million and 50% of annual earned savings between $70 million and $145 million (all figures pre-tax). Earned savings represents the difference between calendar year 2008 distribution revenue and the company's cost of providing service, including a regional average authorized return. These efficiency incentive mechanisms provide an opportunity to achieve returns in excess of traditional regulatory allowed returns. Massachusetts Electric will be allowed to include its share of earned savings in demonstrating its costs of providing service to customers from January 2010 until May 2020.

In Rhode Island, Narragansett Electric's distribution rates are governed by a long-term rate plan. Between May 2000 and the end of October 2004, rates were frozen and Narragansett was permitted to retain 100% of its earnings up to an allowed return on equity of 12%. Narragansett kept 50% of earnings between 12% and 13%, and 25% of earnings in excess of 13%. Effective from November 2004 until December 2009, Narragansett Electric has agreed to freeze its rates after an initial reduction of $10.2 million per year. Beginning in January 2005, it will be able to keep an amount equal to 100% of its earnings up to an allowed ROE of 10.5%, plus $4.65 million (pre-tax), which represents its share of earned savings. Earnings above that amount up to an additional

1% ROE are to be shared equally between Narragansett and its customers, while additional earnings will be allocated 75% to customers and 25% to Narragansett.

New England Power Company (NEP) is a participating transmission owner (PTO) in New England's Regional Transmission Organization (RTO) which commenced operations effective February 1, 2005. ISO New England, Inc. (ISO) has been authorized by FERC to exercise the operations and system planning functions required of RTOs and will be the independent regional transmission provider under the ISO Open Access Transmission Tariff (ISO-OATT). The ISO-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 two orders in 2004 and two in 2005 that approved the establishment of the RTO and resolved certain issues concerning the proposed ROE for New England PTOs. Other return issues were set for hearing. A number of parties, including NEP, filed appeals from one or more of those orders with the US Court of Appeals for the District of Columbia Circuit.

NEP's currently allowed ROE for transmission assets is 10.25%. Effective on the RTO operations date of February 1, 2005, NEP's transmission rates began to reflect a proposed base return on equity of 12.8%, subject to refund, plus the additional 0.5% incentive return on regional network service (RNS) rates that FERC approved in March 2004. Approximately 70% of the Company's transmission costs are recovered through RNS rates. An additional 1.0% incentive adder is also applicable to new RNS transmission investment, subject to refund.

NEP and the other PTOs participated in FERC proceedings to determine outstanding ROE issues, including base ROE and the proposed 1% ROE incentive for new transmission investment. On May 27, 2005, the administrative law judge issued an initial decision which concluded that the base ROE should be 10.72% and that NEP and other PTOs are not entitled to the proposed 1% ROE incentive. All parties will have the opportunity to file a brief on exceptions in response to the judge's initial decision. A final FERC order is expected by year end 2005.

CRITICAL ACCOUNTING POLICIES

There are certain critical accounting policies that are based on assumptions and conditions that if changed could have a material effect on the financial condition, results of operations and liquidity of the Company. The following accounting policies are particularly important to the financial condition and results of operations of the Company: regulatory accounting (including the collection of purchase power costs through the commodity adjustment clause and purchased gas through the gas cost collection mechanism), derivative accounting, revenue recognition, goodwill accounting, and pension accounting.

Regulatory Accounting

Electric and gas utilities are subject to certain accounting standards that are generally not applicable to other business enterprises. The Company applies the provisions of Statement of Financial Accounting Standards (FAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (FAS 71), 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. In 1997, the Emerging Issues Task Force of the Financial Accounting Standards Board (FASB) concluded that an electric utility that had received approval to recover stranded costs through regulated rates would be permitted to continue to apply FAS 71 to the recovery of stranded costs.

The Company has received authorization from regulatory authorities to recover through Contract Termination Charges (in New England) and Competitive Transition Charges (in New York) (collectively, CTCs) substantially all of the costs associated with its former generating business not recovered through the divestiture of the generating business. CTCs are mechanisms that were established to provide for the Company's recovery of stranded costs from customers. Additionally, FERC Order No. 888 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 costbased rate regulation.

Regulatory assets and liabilities typically include deferral of under recovered or over recovered energy costs, environmental restoration costs, post retirement benefit costs, the normalization of income taxes and the deferral of losses incurred on debt retirements. The Company continually assesses whether its regulatory assets and liabilities continue to meet criteria for future recovery or refund, respectively. This assessment considers factors such as changes in the regulatory environment, recent rate orders to the other regulated entities under the same jurisdiction and the status of any pending or potential deregulation legislation. If future recovery of costs becomes no longer probable, the assets and liabilities would be recognized as current-period revenue or expense.

Amortization of regulatory assets is provided over the recovery period as allowed by the related regulatory agreement. Amortization of the stranded cost regulatory asset is shown separately (as it is the largest component of regulatory assets). Amortization of other regulatory assets are included in depreciation and amortization, purchased electricity and gas and other operation and maintenance expense captions on the income statement (depending on the origin of the regulatory asset).

Derivatives

The Company accounts for derivative financial instruments under SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (FAS 133), and SFAS No. 149, "Amendment of SFAS No. 133 on Derivative Instruments and Hedging Activities," as amended. Under the provisions of FAS 133, all derivatives except those qualifying for the normal purchase/normal sale exception are recognized on the balance sheet at their fair value. Fair value is determined using current quoted market prices. If a contract is designated as a cash flow hedge, the change in its market value is generally deferred as a component of other comprehensive income until the transaction it is hedging is completed. Conversely, the change in the market value of a derivative not designated as a cash flow hedge is deferred as a regulatory asset or liability. A cash flow hedge is a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. To qualify as a cash flow hedge, the fair value changes in the derivative must be expected to offset 80% to 120% of the changes in fair value or cash flows of the hedged item.

Niagara Mohawk has received approval from the New York State Public Service Commission (PSC) to establish a regulatory asset or liability for derivative instruments that did not qualify for hedge accounting and were the result of regulatory rulings.

Revenue Recognition

Revenues from the sale of electricity and gas to customers are generally recorded when electricity and gas are delivered to those customers. The quantity of those sales is measured by customers' meters. Meters are read on a systematic basis throughout the month based on established meter-reading schedules. Consequently, at the end of any month, there exists a quantity of electricity and gas that has been delivered to customers but has not been captured by the meter readings. As a result, management must estimate revenue related to electricity and gas delivered to customers between their meter read dates and the end of the period.

Goodwill

The company applies the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets" (FAS 142). In accordance with FAS 142, goodwill must be reviewed for impairment at least annually and when events indicate the asset may be impaired. The Company utilizes 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 adjustment to the goodwill carrying value was required.

Tax Provision

The Company's tax provisions, including both current and deferred components, are based on estimates, assumptions, calculations and interpretation of tax statutes for the current and future years in accordance with SFAS No. 109, "Accounting for Income Taxes". Federal income tax returns have been examined and all appeals and issues have been agreed upon by the Internal Revenue Service and the Company through March 22, 2000.

Management regularly makes assessments of tax return outcomes relative to financial statement tax provisions and adjusts the tax provisions in the period when facts become final.

Pensions

The Company has recognized a net additional minimum pension liability of $290 million on its balance sheet reflecting an underfunded pension obligation. The Company's subsidiaries, NEP and Niagara Mohawk, due to the nature of their respective rate plans, recorded a regulatory asset. (See Note G – "Employee Benefits.")

In addition to the market returns, various other assumptions also affect the pension and other post-retirement benefit expense and measurement of their respective obligations. The more significant assumptions include the assumed return on assets, discount rate, and in the case of retiree healthcare benefits, medical trend assumptions. All ongoing costs of qualified pension and post-retirement healthcare benefits plans are recoverable from customers through reconciling provisions of the Merger Rate Plans.

- ***Assumed return on assets.*** The estimated rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of our long-term assumption. A small premium is added for active management of both equity and fixed income. The rates of return for each asset class are then weighted in accordance with our target asset allocation, and the resulting long-term return on asset rate is then applied to the market-related value of assets. For fiscal 2005, the Company used an 8.50% assumed return on assets for its pension plan and an 8.26% assumed return on assets for its other post-retirement benefits plans, respectively.
- ***Discount rate.*** In determining the discount rate, the Company considers Moody's Aa rates for corporate bonds and public utility bonds. In addition, the Company considers other measures of interest rates for high quality fixed income investments which match the duration of the liabilities. A rate is chosen within the range set by these measures.
- ***Medical trend assumptions.*** The health care cost trend rate is the assumed rate of increase in per-capita health care charges. For 2005, the health trend was set at 10% with the ultimate trend of 5% reached in 2010.

RESULTS OF OPERATIONS

EARNINGS

Net income for the fiscal year ended March 31, 2005 increased approximately $288 million (108%) as compared to the prior year. The increase was primarily due to reductions in the following (i) operating expenses - $345 million, (ii) other deductions - $27 million, and (iii) interest expense - $38 million. The reductions in expenses were partially off set by a reduction in revenue of approximately $122 million. See the following discussions of revenues, operating expenses and other income (deductions) for more detailed explanations.

Net income for the twelve months ended March 31, 2004 decreased approximately $44 million (14%) as compared to the prior year. This decrease was primarily a result of non-recurring costs related to the merger with Niagara Mohawk, partially offset by reduced interest costs resulting from the redemption or refinancing of long-term debt.

ELECTRIC

The Company's electricity business encompasses the transmission, distribution, and delivery of electricity in New England and New York including stranded cost recoveries. The Company's New England distribution subsidiaries (Massachusetts Electric, Narragansett Electric, Granite State Electric and Nantucket Electric) are responsible for the distribution and sale of electricity to customers while NEP is responsible for the transmission of electricity. For New York, Niagara Mohawk is responsible for the transmission, distribution, and sale of electricity. Electric results are discussed by geography.

The Company is no longer in the business of electricity generation and has divested the vast majority of its formerly owned generation assets (the Company still retains a nine percent joint ownership interest in the Wyman #4 generating unit in Maine, which the Company is attempting to sell). Since deregulation, electricity customers have the ability to choose an alternative supplier of their electricity other than the retail distribution company serving that customer's region. For customers who have not chosen an alternative supplier, the Company procures power on their behalf. These energy procurement costs (i.e. purchased electricity expenses) are recoverable from customers and do not impact the company's electric margin or net income.

Electric margin in New England increased approximately $5 million and $11 million for the fiscal years ended March 31, 2005 and 2004, respectively. The table below details the components of these increases.

New England
Electric Operating Margin ($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Electric revenue	**$ 3,146,451**	$ 3,130,308	$ 2,784,518	$ 16,143	*0.5*	$ 345,790	*12.4*
Less:							
Electricity purchased	**1,546,288**	1,553,483	1,176,035	(7,195)	*(0.5)*	377,448	*32.1*
Amortization of stranded costs	**67,344**	70,710	72,394	(3,366)	*(4.8)*	(1,684)	*(2.3)*
CTC and nuclear shutdown charges	**149,140**	145,517	161,583	3,623	*2.5*	(16,066)	*(9.9)*
Other O&M - fuel for generation	**1,125**	4,503	9,125	(3,378)	*(75.0)*	(4,622)	*(50.7)*
Other O&M - transmission expenses	**181,076**	158,721	192,273	22,355	*14.1*	(33,552)	*(17.5)*
Other O&M - energy efficiency costs	**72,402**	73,534	66,074	(1,132)	*(1.5)*	7,460	*11.3*
Other taxes - gross receipts tax	**30,027**	29,735	24,031	292	*1.0*	5,704	*23.7*
Electric margin	**$ 1,099,049**	$ 1,094,105	$ 1,083,003	$ 4,944	*0.5*	$ 11,102	*1.0*

Electric margin in New York increased approximately $9 million and decreased $39 million for the fiscal years ended March 31, 2005 and 2004, respectively. The table below details the components of these changes.

New York
Electric Operating Margin ($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Electric revenue	**$ 3,117,156**	$ 3,284,017	$ 3,310,837	$ (166,861)	*(5.1)*	$ (26,820)	*(0.8)*
Less:							
Electricity purchased	**1,364,813**	1,591,652	1,594,221	(226,839)	*(14.3)*	(2,569)	*(0.2)*
Amortization of stranded costs	**251,500**	194,114	149,415	57,386	*29.6*	44,699	*29.9*
Other O&M - energy efficiency costs	**39,096**	39,283	39,468	(187)	*(0.5)*	(185)	*(0.5)*
Gross receipts tax expense	**16,031**	21,857	52,012	(5,826)	*(26.7)*	(30,155)	*(58.0)*
Electric margin	**$ 1,445,716**	$ 1,437,111	$ 1,475,721	$ 8,605	*0.6*	$ (38,610)	*(2.6)*

Descriptions of individual line items are provided below under their respective headings.

Electric sales increased approximately 665 GWh (1%) in fiscal 2005 as compared to the prior year and decreased approximately 528 GWh (<1%) in fiscal 2004 compared to fiscal 2003. An analysis by customer class is provided below.

Electric Sales Volumes (GWh)
Actual

				% Change	
	2005	2004	2003	FY05 vs FY04	FY04 vs FY03
New England:					
Residential	**11,801**	11,788	11,507	*0.1*	*2.4*
Commercial	**13,313**	13,126	13,066	*1.4*	*0.5*
Industrial/Other	**5,438**	5,455	5,666	*(0.3)*	*(3.7)*
Total - New England	**30,552**	30,369	30,239	*0.6*	*0.4*
New York:					
Residential	**10,939**	10,935	10,925	*0.0*	*0.1*
General Service	**11,045**	10,775	10,756	*2.5*	*0.2*
Large Time-of-Use	**7,256**	6,732	7,104	*7.8*	*(5.2)*
NYPA/Other	**5,280**	5,596	5,911	*(5.6)*	*(5.3)*
Total - New York	**34,520**	34,038	34,696	*1.4*	*(1.9)*
Total - NE and NY	**65,072**	64,407	64,935	*1.0*	*(0.8)*

The following table reflects weather normalized volumes.

Electric Sales Volumes (GWh)
Weather Normalized

	2005	2004	2003	% Change FY05 vs FY04	FY04 vs FY03
New England:					
Residential	**11,771**	11,515	11,008	*2.2*	*4.6*
Commercial	**13,303**	13,015	12,822	*2.2*	*1.5*
Industrial/Other	**5,440**	5,434	5,652	*0.1*	*(3.9)*
Total - New England	**30,514**	29,964	29,482	*1.8*	*1.6*
New York:					
Residential	**11,075**	10,932	10,447	*1.3*	*4.6*
General Service	**11,116**	10,778	10,558	*3.1*	*2.1*
Large Time-of-Use	**7,264**	6,736	7,071	*7.8*	*(4.7)*
NYPA/Other	**5,280**	5,596	5,911	*(5.6)*	*(5.3)*
Total - New York	**34,735**	34,042	33,987	*2.0*	*0.2*
Total - NE and NY	**65,249**	64,006	63,469	*1.9*	*0.8*

New England Customer Classes

- Residential customer sales are to single, as well as multi-family, residences and group homes, farms, and religious institutions (churches, schools, seminaries, retreats, conference centers, etc.).
- Commercial sales are to small and large commercial accounts including office, warehouse, retail, school, hotel, restaurant, hospitals/health, government and street lighting.
- Industrial/Other sales are to small and large industrial accounts, including plants, factories, mills and any other establishments primarily engaged in the manufacturing of finished, intermediate, durable or non-durable goods.

New York Customer Classes

- Residential customer sales are to single, as well as multi-family, residences and group homes, farms, and religious institutions (churches, schools, seminaries, retreats, conference centers, etc.).
- General Service sales consist of commercial accounts and light industry served under standard tariff provisions.
- Large Time-of-Use sales encompass the heavy industrial as well as several very large commercial campuses (educational and health care) and customers receiving discount power under special contracts and station stand-by service.
- NYPA/Other are sales generally made to large industrial loads that are supplied from the Niagara Falls Power Project through Company owned transmission lines. NYPA sales also consist of NYPA administered discount power through the Economic Development Power program and the Power for Jobs programs. Customers whose power contracts expire and who subsequently continue to purchase power from Niagara Mohawk are accounted for in either large time-of-use sales or general service sales. Other accounts are primarily Street and Highway Lighting as well as Private Area Lighting.

Seasonality & Weather impacts

Electricity customer load varies by season, usually peaking in the winter and summer months. The lower and higher temperatures in those months drive higher electricity sales as more electricity is used for heating or cooling during those months. The New England and New York regions experienced more extreme weather temperatures during fiscal 2004 (with higher than average temperatures in the summer months and lower average temperatures in winter months).

Weather had a negative impact on consolidated electric margin of approximately $19 million for the year ended March 31, 2005 and a positive impact of approximately $11 million for the year ended March 31, 2004.

Economic impacts

During fiscal year 2005, the New York region began recovering from the industrial recession during fiscal years 2003 and 2004. During fiscal 2005, deliveries of electricity to non-residential accounts expanded by 5.3% following four years of steady decline. The residential sector in the New York service area expanded 1.3% during fiscal 2005 (versus 3%+ in the two previous years) as the regional housing boom began winding down. In New England, residential energy deliveries grew at a 2.2% rate in fiscal year 2005, but this was still much less than the pace of the previous two years. Industrial energy deliveries stabilized, increasing 0.1% after three consecutive years of decline while commercial deliveries grew at the same rate as residential, 2.2%.

Electric revenues decreased approximately $151 million (2%) and increased approximately $319 (5%) for the fiscal years ended March 31, 2005 and 2004, respectively. The table below details components of these fluctuations.

Electric Revenue ($'s in 000's)

Actual

	2005	2004	2003	FY05 vs FY04 $ Change	FY05 vs FY04 % Change	FY04 vs FY03 $ Change	FY04 vs FY03 % Change
Retail Sales							
Residential	**$ 2,708,421**	$2,820,271	$2,717,843	$ (111,850)	*(4.0)*	$ 102,428	*3.8*
Commercial	**2,203,203**	2,072,745	1,976,829	130,458	*6.3*	95,916	*4.9*
Industrial	**726,295**	743,761	785,282	(17,466)	*(2.3)*	(41,521)	*(5.3)*
Street lighting	**77,423**	71,869	62,303	5,554	*7.7*	9,566	*15.4*
Total retail sales	**5,715,342**	5,708,646	5,542,257	6,696	*0.1*	166,389	*3.0*
Sales for resale	**126,706**	223,789	249,574	(97,083)	*(43.4)*	(25,785)	*(10.3)*
Transmission revenue	**259,903**	228,427	235,739	31,476	*13.8*	(7,312)	*(3.1)*
Refund provisions	**5,590**	97,190	(82,455)	(91,600)	*(94.2)*	179,645	*(217.9)*
Other revenues	**156,066**	156,273	150,240	(207)	*(0.1)*	6,033	*4.0*
	$ 6,263,607	$6,414,325	$6,095,355	$ (150,718)	*(2.3)*	$ 318,970	*5.2*

- Total retail sales for fiscal year 2005 were relatively consistent with the prior year. The Company, through various rate mechanisms, passes on to customers changes in its cost of purchased power. The approximately $166 million increase in retail sales for the year ended March 31, 2004 was primarily attributable to an increase in purchased power costs.
- Sales for resale are revenues generated from selling electricity to other public utilities or municipal utilities. The $97 million decrease in fiscal year 2005 compared to fiscal year 2004 is primarily due to a decrease in Niagara Mohawk sales to the New York Independent System Operator (NYISO) of approximately $89 million. In New York, all electricity purchased under certain purchased power contracts is sold to the NYISO. The decrease in sales to the NYISO for the year ended March 31, 2005 was due to the expiration of some of these contracts.
- Transmission revenue is revenue derived from transmission wheeling (transmitting the electricity of other utilities over Company-owned transmission lines). The $31 million increase during fiscal 2005 was primarily attributable to retail electric customers migrating to competitive suppliers for their commodity requirements.
- Refund provisions primarily relate to the New England distribution companies' (Massachusetts Electric, Narragansett Electric, Granite State Electric and Nantucket Electric) deferral mechanisms for the over and under collection of electricity procurement costs. Electricity is procured for customers who have not chosen an alternative energy supplier. These purchased electricity costs fluctuate from month to month, but the rate charged to customers changes less often. This results in either a temporary over or under collection of costs. The refund provision reflects this over or under recovery with an offset to a regulatory asset or liability for recovery or refund in the following year. Periodically, the customer rates for electricity procurement (shown as a "generation" charge on the customers' bills) are adjusted to reflect actual or forecasted purchased electricity costs along with an increase or reduction for any under or over collection of prior period costs. In fiscal 2005

and 2004 there was an under collection of costs. This portion of revenue has no impact on electric margin or net income due to equal offsets in purchased electricity (cost of power) and retail sales revenue (generation rate revenue).

- Other revenue consists of miscellaneous ancillary revenues such as rental income from electric properties (e.g. usage of pole space for wires by the telephone and cable companies).

Electricity purchased decreased approximately $234 million (7.4%) in the current year. These costs represent the cost for the Company to procure electricity for its customers who have not chosen an alternative energy supplier. These costs do not impact electric margin or net income as the Company's rate plans allow full recoverability of these costs from customers. The decrease in expense primarily relates to New York and is the result of a 5.5 billion (17%) decrease in the volume of kWh purchased due to customers migrating to competitive electricity suppliers and less extreme weather in the current year.

Electricity purchased increased approximately $375 million (13.5%) in the fiscal year ended March 31, 2004. The increase in expense was primarily the result of increased prices being charged to the Company for electricity to be distributed to its customers.

GAS

Niagara Mohawk is also a gas distribution company that services customers in cities and towns in central and eastern New York. Niagara Mohawk's gas rate plan allows it to recover all commodity costs (i.e. the purchasing, interstate transportation and storage of gas for sale to customers) from customers (similar to the recoverability of purchased electricity).

Gas margin after one-time items decreased approximately $4.6 million (1.5%) in the fiscal year ended March 31, 2005 and decreased approximately $1.3 million (0.4%) in the fiscal year ended March 31, 2004. The table below details the components of these changes.

Gas Operating Margin ($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Gas revenue	**$ 808,015**	$ 779,600	$ 708,613	$ 28,415	*3.6*	$ 70,987	*10.0*
Less:							
Gas purchased	**509,543**	478,647	393,796	30,896	*6.5*	84,851	*21.5*
Other taxes - gross receipts tax	**9,236**	13,123	13,746	(3,887)	*(29.6)*	(623)	*(4.5)*
Gas margin	**289,236**	287,830	301,071	1,406	*0.5*	(13,241)	*(4.4)*
Gas revenue - state income tax adjustment	**-**	(5,957)	5,957	5,957	*(100.0)*	(11,914)	*(200.0)*
Gas margin after one-time item	**$ 289,236**	$ 293,787	$ 295,114	$ (4,551)	*(1.5)*	$ (1,327)	*(0.4)*

The $4.6 million decrease in gas margin after a one-time item comparing fiscal 2005 to fiscal 2004 is primarily due to the elimination of the $6 million state income tax adjustment recorded in the prior period, partially offset by an increase in gas margin of $1.4 million. The state income tax adjustment is a non-cash item included in revenue (with the offsetting expense included in Income Taxes). In fiscal 2003, approximately $10 million was accrued in revenue as estimated state income tax expense (as state income taxes are recoverable through the Company's rate agreement). In fiscal 2004, when the state income taxes were reconciled and paid it was determined that the Company over-accrued its income tax liability by approximately $6 million and subsequently reversed the over-accrual.

Gas throughput for the fiscal years ended March 31, 2005 and 2004, excluding transportation of customer-owned gas, decreased approximately 3.7 and 3.6 million dekatherms (Dth), respectively. An analysis by customer class is provided below.

Gas Throughput Volumes (000's of Dth)

Actual

				% Change	
	2005	2004	2003	FY05 vs FY04	FY04 vs FY03
Retail					
Residential	**46,025**	48,699	51,533	*(5.5)*	*(5.5)*
Commercial	**14,579**	15,479	16,334	*(5.8)*	*(5.2)*
Industrial	**396**	521	440	*(24.0)*	*18.4*
Other	**1**	2	7	*(50.0)*	*(71.4)*
Total retail	**61,001**	64,701	68,314	*(5.7)*	*(5.3)*
Transportation	**80,329**	83,548	114,286	*(3.9)*	*(26.9)*
Total gas sales volume	**141,330**	148,249	182,600	*(4.7)*	*(18.8)*

Gas Throughput Volumes (000's of Dth)

Weather Normalized

				% Change	
	2005	2004	2003	FY05 vs FY04	FY04 vs FY03
Retail					
Residential	**46,105**	47,995	49,336	*(3.9)*	*(2.7)*
Commercial	**14,524**	15,316	15,658	*(5.2)*	*(2.2)*
Industrial	**396**	521	440	*(24.0)*	*18.4*
Other	**1**	2	7	*(50.0)*	*(71.4)*
Total retail	**61,026**	63,834	65,441	*(4.4)*	*(2.5)*
Transportation	**80,239**	83,217	113,322	*(3.6)*	*(26.6)*
Total gas sales volume	**141,265**	147,051	178,763	*(3.9)*	*(17.7)*

Retail

Retail throughput represents throughput related to both the distribution (transportation) of the gas and the commodity itself. The decrease in retail throughput comparing fiscal 2005 to fiscal 2004 is primarily due to (i) a decrease in use-per-customer primarily resulting from increased gas prices and (ii) less extreme weather in the current year.

Transportation

Transportation throughput represents throughput related to the distribution of gas only, not including the commodity itself. The decline in transportation throughput is largely driven by the Company's special contract class (customers who are subject to special contracts whereby margin is not linked to throughput). The decline in throughput does not translate into a decline in margin as these classes are subject to a true-up to a target which is set independently in the Company's rate case proceeding.

The decrease in transportation throughput for fiscal 2004 compared to fiscal 2003 is largely driven by the Company's Special Contract and Interruptible classes.

Seasonality and weather impacts

Gas customer throughput varies by season, with loads usually peaking in the winter months. The lower temperatures in the winter months drive higher gas throughput, as more gas is used for heating during colder months. The New York region experienced less extreme weather temperatures during the winter of fiscal 2005 compared to prior winters.

The Company's gas rate agreement also includes a weather normalization clause to mitigate the impact that unseasonable weather could have on gas margin during the peak gas sales season (winter). This normalization clause compares the 30-year historical average temperature for the day to the current temperature, and if the current temperature is 2.2% higher or lower than the historical average the Company will either surcharge (due to lower throughput) or discount (due to greater throughput) the customer.

Gas revenues increased $28 million (3.6%) in the current year. This increase is primarily a result of higher gas prices being passed through to the customers, partially offset by a decrease in throughput.

Revenue by Customer Type

($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Retail							
Residential	**$ 521,593**	$ 513,631	$ 465,029	$ 7,962	*1.6*	$ 48,602	*10.5*
Commercial	**160,768**	154,806	137,908	5,962	*3.9*	16,898	*12.3*
Industrial	**3,482**	4,103	3,038	(621)	*(15.1)*	1,065	*35.1*
Other	**44,479**	26,670	25,727	17,809	*66.8*	943	*3.7*
Total retail	**730,322**	699,210	631,702	31,112	*4.4*	67,508	*10.7*
Transportation	**77,693**	80,390	76,911	(2,697)	*(3.4)*	3,479	*4.5*
Total revenue	**$ 808,015**	$ 779,600	$ 708,613	$ 28,415	*3.6*	$ 70,987	*10.0*

Revenue by Component

($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Retail							
Commodity cost	**$ 509,543**	$ 478,647	$ 393,796	$ 30,896	*6.5*	$ 84,851	*21.5*
Delivery	**199,145**	201,503	207,944	(2,358)	*(1.2)*	(6,441)	*(3.1)*
Other	**21,634**	19,060	29,962	2,574	*13.5*	(10,902)	*(36.4)*
Total retail	**730,322**	699,210	631,702	31,112	*4.4*	67,508	*10.7*
Transportation							
Delivery	**76,959**	79,415	75,518	(2,456)	*(3.1)*	3,897	*5.2*
Other	**734**	975	1,393	(241)	*(24.7)*	(418)	*(30.0)*
Total transportation	**77,693**	80,390	76,911	(2,697)	*(3.4)*	3,479	*4.5*
Total revenue	**$ 808,015**	$ 779,600	$ 708,613	$ 28,415	*3.6*	$ 70,987	*10.0*

- The commodity cost portion of revenue represents the recovery of the purchased gas costs and the increase in the revenue mirrors the increase in purchased gas expense. As such, the commodity cost revenue has no impact on gas margin or net income.
- Delivery revenue represents the income from distribution of gas and does impact the Company's margin. The decrease in delivery revenue comparing fiscal year 2005 to fiscal year 2004 is primarily due to lower gas throughput.
- Other gas revenue is primarily related to the recovery of costs associated with the gross-receipts tax and state income tax, which, like purchased gas expense, is fully recoverable from customers. The increase in Other is primarily due to the fiscal 2005 year not including an adjustment related to the state net income tax which was included in the prior year (discussed above in gas margin).

Gas revenues increased $71 million (10%) in the fiscal year ended March 31, 2004. The increase was primarily a result of higher gas prices being passed through to customers, partially offset by a decrease in throughput.

Gas purchased expense increased approximately $31 million (6.5%) in the current year compared to the prior year. This increase is primarily a result of increased gas prices during the year. The Company's net cost per Dth, as charged to expense, increased to $7.12 in the year ended March 31, 2005 from $6.61 in the prior year. This increase in price was slightly offset by decreased purchases. Gas purchased expense has no impact on the Company's net income as all gas commodity costs are recoverable from customers through a regulatory deferral mechanism in effect.

Gas purchased expense increased approximately $85 million (21.5%) in the fiscal year ended March 31, 2004 compared to the fiscal year ended March 31, 2003. The increase was primarily a result of increased gas prices during the year. The Company's net cost per Dth, as charged to expense, increased to $6.61 in the year ended March 31, 2004 from $5.57 in the prior year. This increase in price was slightly offset by decreased purchases. Quantities purchased and withdrawn from storage were down 3.6 million Dth.

OPERATING EXPENSES

Contract termination and nuclear shutdown charges increased approximately $4 million (3%) in the current year. As part of generation deregulation in New England, NEP divested its generation assets, which included the transfer of long-term purchased power contracts. The Company's CTC reflects the above market costs of the contracts that were transferred at divestiture and the Company's share of ongoing decommissioning and shutdown costs associated with its ownership of three permanently shutdown nuclear plants in New England. Both the contract termination and nuclear shutdown costs are fully provided for in rates and do not affect electric margin or net income. The increase is primarily due to an increase in nuclear decommissioning costs in fiscal 2005 compared with the prior year.

Contract termination and nuclear shutdown charges decreased approximately $16 million (10%) in the twelve months ended March 31, 2004. The decrease was caused by reduced ongoing payments for purchased power due primarily to the buyout of a purchased power contract in November 2002. Also contributing to the decrease was reduced purchased power expense for the fiscal year ended March 31, 2004 as compared with the prior year due to the sale of Vermont Yankee in July 2002. Partially offsetting the decreases was an increase in nuclear shutdown expenses due to the resumption of decommissioning billings by Yankee Atomic in June 2003.

Other operation and maintenance expense for the Company decreased approximately $221 million (14%) and increased approximately $52 million (3%) for the fiscal years ended March 31, 2005 and 2004, respectively. The table below details components of these fluctuations.

Other Operations & Maintenance Expense ($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Period costs:							
Payroll expense	**$ 490,422**	$ 548,524	$ 553,961	$ (58,102)	*(10.6)*	$ (5,437)	*(1.0)*
Pension benefits	**59,468**	55,173	28,202	4,295	*7.8*	26,971	*95.6*
Other employee benefits	**113,981**	114,551	117,921	(570)	*(0.5)*	(3,370)	*(2.9)*
Bad debt	**69,875**	85,028	67,306	(15,153)	*(17.8)*	17,722	*26.3*
Rent and leases	**40,806**	39,520	43,713	1,286	*3.3*	(4,193)	*(9.6)*
Insurance	**35,006**	46,467	36,480	(11,461)	*(24.7)*	9,987	*27.4*
Regulatory commission fees	**24,711**	22,507	19,866	2,204	*9.8*	2,641	*13.3*
Other	**210,486**	183,873	186,805	26,613	*14.5*	(2,932)	*(1.6)*
Total period costs	**1,044,755**	1,095,643	1,054,254	(50,888)	*(4.6)*	41,389	*3.9*
Pass-through items:							
Energy efficiency costs	**111,498**	112,817	105,542	(1,319)	*(1.2)*	7,275	*6.9*
Transmission expenses	**181,076**	158,721	192,273	22,355	*14.1*	(33,552)	*(17.5)*
Total pass-through items	**292,574**	271,538	297,815	21,036	*7.7*	(26,277)	*(8.8)*
Integration-related costs:							
ERP system implementation costs	**14,787**	18,813	9,147	(4,026)	*(21.4)*	9,666	*105.7*
Voluntary early retirement program	**(25,112)**	116,857	-	(141,969)	*(121.5)*	116,857	*100.0*
Other integration related costs	**26,965**	36,171	46,978	(9,206)	*(25.5)*	(10,807)	*(23.0)*
Total integration-related costs	**16,640**	171,841	56,125	(155,201)	*(90.3)*	115,716	*206.2*
Atypical costs:							
April 2003 ice storm	**-**	5,700	-	(5,700)	*(100.0)*	5,700	*100.0*
Pension settlement (recovery)/losses	**(14,485)**	23,144	29,548	(37,629)	*(162.6)*	(6,404)	*(21.7)*
Loss on sale of properties	**7,200**	-	-	7,200	*100.0*	-	-
CWIP write-off	**-**	-	18,960	-	-	(18,960)	*(100.0)*
New York bad debt write-off	**-**	-	42,376	-	-	(42,376)	*(100.0)*
Seabrook nuclear generation facility expenses	**-**	-	16,705	-	-	(16,705)	*(100.0)*
Total atypical costs	**(7,285)**	28,844	107,589	(36,129)	*(125.3)*	(78,745)	*(73.2)*
Total other operating and maintenance	**$ 1,346,684**	$ 1,567,866	$ 1,515,783	$ (221,182)	*(14.1)*	$ 52,083	*3.4*

Period costs

These costs include employment costs (including pension expense) and other costs incurred in maintaining the electricity transmission and distribution systems, and the gas distribution system.

- Payroll expense has decreased due to staffing reductions through the voluntary early retirement programs that occurred in fiscal 2004. Fiscal year 2005 represents a full year of the savings associated with these programs.
- The increase in employee benefits comparing fiscal year 2004 to fiscal year 2003 was primarily due to a decrease in the discount rate used to calculate the expense and the

effects of the decreased value of the plan assets due to poor market performance (primarily in the equities market).

- The decrease in bad debt expense for the year ended March 31, 2005 was mainly the result of improved collections in New York.
- Insurance expense decreased primarily due to decreased third-party claims against the Company, decreases in employee accident claims and an expanded emphasis on safety practices, partially offset by higher insurance premiums due to insurance market conditions.
- Regulatory commission fees are fees paid to the FERC and the state utility commissions having jurisdiction.

Pass-through items

These costs do not affect operating income or net income as they are recovered through reconciling rate adjustments or are deferred under the Company's rate plans.

- Energy conservation expenses include New England's costs incurred for programs to reduce energy consumption by customers through various energy efficiency programs. The New England retail distribution companies manage their own energy efficiency programs while the New York program is managed by the New York State Energy Research and Development Authority which assesses the Company a fee.
- Transmission expenses represent New England transmission costs (wheeling, load dispatching, substations, etc) that are recoverable through rate agreements. The $22 million increase during fiscal 2005 compared to fiscal 2004 is primarily related to wheeling (transmitting Company electricity over transmission lines owned by other utilities) and due to retail electric customers migrating to competitive suppliers for their commodity requirements.

Integration-related costs

- Enterprise resource planning system implementation costs reflect non-capitalizable costs for new information systems that were implemented on May 1, 2004.
- Voluntary early retirement program costs reflect the special termination benefits offered to employees to reduce staffing redundancies. During fiscal year 2005, Narragansett Electric was permitted recovery approximately $23 million of its pension and post retirement benefit obligations other than pension cost that had been expensed in fiscal year 2004.
- Other costs related to the Company's integration of Niagara Mohawk, such as severance pay, building consolidations, etc.

Atypical costs

These items are expenses that the Company considers outside the scope of normal recurring costs.

- In April 2003 the Company experienced an ice storm in its upstate New York service territory which resulted in excessive repair and power restoration costs beyond normal storm costs.
- Pension settlement losses have resulted primarily from significant lump-sum cash withdrawals made by retirees of Niagara Mohawk. The pension settlement loss recovery of $14 million reflects the PSC's July 2004 approval for Niagara Mohawk to recover a portion of the $30 million pension settlement loss incurred in fiscal 2003. Niagara Mohawk has petitioned the Public Service Commission (PSC) for recovery for $21 million of the pension settlement loss that was recorded to expense in fiscal 2004.
- During fiscal year 2005, the Company recognized a loss on the sale of the following three properties (i) Buffalo Electric building - $3.5 million, (ii) Towpath property - $0.5 million and (iii) O'Neil building - $3.2 million.
- The Company recorded a charge of $19 million in fiscal 2003 to write off certain pre-acquisition Niagara Mohawk projects in its construction work-in-process (CWIP) accounts resulting from a post-acquisition review of pre-acquisition CWIP projects.
- The Company adjusted Niagara Mohawk's estimated allowance for doubtful accounts for customer receivable accounts with balances greater than 90 days in arrears which resulted in an additional expense of approximately $42 million in fiscal 2003.

- Other costs related to the Company's integration of Niagara Mohawk, such as severance pay, building consolidations, etc.

Depreciation and amortization remained relatively unchanged in the current year. These expenses consist of the depreciation and amortization of the Company's various electric and gas facilities.

Amortization of stranded costs increased approximately $54 million (20.4%) and $43 million (19.4%) for the years ended March 31, 2005 and 2004, respectively. Stranded costs represent unrecovered costs associated with the Company's former participation in the electric generation business. These stranded costs consist primarily of the accrued above-market costs associated with various purchased power contracts, as well as unrecovered costs of formerly owned generation assets. At the time these costs were incurred or accrued, they were deferred to a regulatory asset account to be amortized at a later date. The Company's revenues currently include an allowance for the amortization of these costs plus a return. The increase in the expense results primarily from scheduled amortization under Niagara Mohawk's rate plan, in which its stranded costs are amortized unevenly on an increasingly graduated schedule over a ten-year period (which began January 1, 2002).

Other taxes decreased approximately $21 million (6%) in the current year. The table below details components of this fluctuation.

Other taxes ($'s in 000's)

				FY05 vs FY04		FY04 vs FY03	
	2005	2004	2003	$ Change	% Change	$ Change	% Change
Property taxes							
New England-Electric	$ 61,382	$ 70,188	$ 75,290	$ (8,806)	*(12.5)*	$ (5,102)	*(6.8)*
New York-Electric	133,720	129,490	122,114	4,230	*3.3*	7,376	*6.0*
New York-Gas	33,457	32,759	30,817	698	*2.1*	1,942	*6.3*
Total property taxes	228,559	232,437	228,221	(3,878)	*(1.7)*	4,216	*1.8*
Gross earnings taxes							
New England-Electric	30,027	29,735	24,031	292	*1.0*	5,704	*23.7*
New York-Electric	16,031	21,857	52,012	(5,826)	*(26.7)*	(30,155)	*(58.0)*
New York-Gas	9,236	13,123	13,746	(3,887)	*(29.6)*	(623)	*(4.5)*
Total gross earnings taxes	55,294	64,715	89,789	(9,421)	*(14.6)*	(25,074)	*(27.9)*
Sales, Use & Utility taxes	1,427	4,629	9,223	(3,202)	*(69.2)*	(4,594)	*(49.8)*
Payroll taxes	34,989	39,263	39,514	(4,274)	*(10.9)*	(251)	*(0.6)*
Unemployment taxes	1,990	2,399	1,955	(409)	*(17.0)*	444	*22.7*
Other	-	91	398	(91)	*(100.0)*	(307)	*(77.1)*
Total other taxes	$ 322,259	$ 343,534	$ 369,100	$ (21,275)	*(6.2)*	$ (25,566)	*(6.9)*

Other taxes decreased approximately $21 million (6%) and $26 million (7%) in the years ended March 31, 2005 and 2004, respectively. Property taxes in New England have been rising steadily due to increases in the underlying property values, however, the Company has implemented specific programs in New England to offset the increases. The decrease in fiscal year 2005 property taxes in New England is partially due to a tax refund and settlement agreement which provides credits in relation to property taxes from 2007 to 2012. The decrease in New England property taxes of $5 million comparing fiscal year 2004 to fiscal year 2003 is primarily due to an overestimation of New England property tax expense in fiscal 2003 by $3 million, which was subsequently reversed in fiscal 2004.

Property taxes in New York increased due to increases in the underlying tax rates. The decrease in New York's gross receipts taxes (GRT) is due to reductions in the underlying tax rates. GRT is fully recoverable under the Company's rate plans and does not impact electric margin, gas margin or net income. Payroll taxes consist of the employer's portion of social security and Medicare taxes and decreased due to a reduction in headcount.

Income taxes increased approximately $37 million (14%) in the current year primarily due to (i) increase in book pre-tax income - $129 million, (ii) decrease in return to provision adjustments (reduction in expense) - $79 million and (iii) other decreases of $13 million.

Income taxes increased approximately $41 million (18%) in year ended March 31, 2004, primarily as a result of a tax increase of $32.3 million due to the interplay of foreign tax credits in the alternative minimum tax calculation.

OTHER INCOME (DEDUCTIONS), INTEREST AND PREFERRED DIVIDENDS

Other income (deductions), net increased $27 million (127%) in the current year. This is primarily attributable to a $9 million settlement of an estimated liability and an $8 million favorable adjustment to non-utility related income taxes at Niagara Mohawk.

Other deductions, net decreased $16 million (44%) in the fiscal year ended March 31, 2004. This was primarily attributable to telecom operations which recorded a $17 million charge for the abandonment of long-term lease obligations as well as the write-off of obsolete inventory in fiscal 2003 as compared to a charge of $10 million for a telecom-related asset impairment in fiscal 2004.

Interest expense decreased $39 million (12%) and $101 million (24%) for the years ended March 31, 2005 and 2004, respectively. The decreases are primarily due to long-term debt maturing and the early redemption of third-party debt using affiliated-company debt at lower interest rates. See "Liquidity and Capital Resources: Financing Activities" below for a detailed description of the various refinancings and redemptions.

LIQUIDITY AND CAPITAL RESOURCES

SHORT TERM

At March 31, 2005, the Company's principal sources of liquidity included cash and cash equivalents of approximately $355 million and accounts receivable of approximately $1.1 billion. The Company has a negative working capital balance of $184 million primarily due to long-term debt due within one year of $568 million and short-term debt due to affiliates of $687 million. Cash is being generated from sales (via electric rates) to offset stranded cost amortization (non-cash expense). This excess cash is used for debt payments and other operating needs. As discussed below, the Company believes it has sufficient cash flow and borrowing capacity to fund such deficits as necessary in the near term. In addition, construction expenditures planned within one year are estimated to be $608 million.

Operating Activities

Net cash provided by operating activities increased approximately $782 million in the current year. The increase is primarily due to:

- Increase in net income (see earnings discussion above) of approximately $288 million.
- Increased stranded cost recovery of $54 million.
- Increased provision for deferred income taxes of approximately $70 million primarily related to net operating loss carryforwards.
- Decreased pension and other retirement benefit plan expense of approximately $113 million.
- Decreased cash paid to pension and postretirement benefit plan trusts of approximately $171 million primarily due to a one time payment made in fiscal year 2004 related to a settlement agreement between Niagara Mohawk and the New York PSC that allows Niagara Mohawk to earn a return on its additional funding.
- Decrease in the change in accounts receivable and accrued interest and taxes of $60 million and $34 million respectively (increases in cash).
- Increase in accounts payable and accrued expenses of approximately $164 million.
- Increases from other changes of approximately $54 million (i.e. changes in materials and supplies, purchased power obligations, etc.).

Investing Activities

Net cash used in investing activities increased approximately $71 million in the current year. This increase was primarily due to an increase in construction additions and an increase in other property and investments. Capital expenditures increased approximately $40 million during fiscal year 2005 primarily due to increased transmission utility plant expenditures at NEP. The funds necessary for utility plant expenditures during the period were primarily provided by internal funds.

Financing Activities

Net cash used in financing activities increased approximately $702 million in the current year. This increase is primarily the result of early redemption of third-party debt with internally generated funds. Also contributing to the increase was a common dividend paid to the Company's parent of $218 million for which there was no similar cash outflow in the prior year.

The Company has been refinancing and redeeming early various issues of debt and preferred stock and replacing them with lower-cost affiliated-company debt.

Description	Company	03/31/2005 Balance	03/31/2004 Balance	$ Change	Activity
Series D Preferred Stock	Niagara Mohawk	$ -	$ 25.1	$ (25.1)	Early redemption
NYSERDA Tax-exempt Pollution Control Bonds	Niagara Mohawk	**413.8**	413.8	-	Refinanced from adjustable rate to variable rate (average 0.99%)
NYSERDA Tax-exempt Pollution Control Bonds	Niagara Mohawk	**45.6**	45.6	-	Refinanced from 6.625% to variable rate (average 1.02%)
8.0% First Mortgage Bonds	Niagara Mohawk	-	232.4	(232.4)	Redeemed
5.38% Senior Notes	Niagara Mohawk	-	300.0	(300.0)	Redeemed
8.52% Series Preferred Stock	Massachusetts Electric	-	10.0	(10.0)	Redeemed
8.45% First Mortgage Bonds	Massachusetts Electric	-	10.0	(10.0)	Redeemed
8.22% First Mortgage Bonds	Massachusetts Electric	-	10.0	(10.0)	Redeemed
7.92% First Mortgage Bonds	Massachusetts Electric	-	9.0	(9.0)	Redeemed
8.08% First Mortgage Bonds	Massachusetts Electric	-	5.0	(5.0)	Redeemed
8.03% First Mortgage Bonds	Massachusetts Electric	-	5.0	(5.0)	Redeemed
8.16% First Mortgage Bonds	Massachusetts Electric	-	5.0	(5.0)	Redeemed
8.85% First Mortgage Bonds	Massachusetts Electric	-	1.0	(1.0)	Redeemed
8.46% First Mortgage Bonds	Massachusetts Electric	-	3.0	(3.0)	Redeemed
5.30% 2004 Series 1996 MIFA Tax Exempt	Nantucket Electric	-	1.4	(1.4)	Redeemed
5.875% 2017 Series 1996 MIFA Tax Exempt	Nantucket Electric	**20.5**	10.5	10.0	Redeemed and re-issued
7.42% First Mortgage Bonds	Narragansett Electric	-	5.0	(5.0)	Redeemed
8.33% First Mortgage Bonds	Narragansett Electric	-	10.0	(10.0)	Redeemed
8.08% First Mortgage Bonds	Narragansett Electric	-	5.0	(5.0)	Redeemed
8.16% First Mortgage Bonds	Narragansett Electric	-	5.0	(5.0)	Redeemed
9.26% Series B	Hydros	**12.1**	21.4	(9.3)	
Notes Payable to affiliated companies	Niagara Mohawk Holdings	**1,200.0**	1,200.0	-	Affiliated company borrowings used to fund Niagara Mohawk's refinancings and redemptions
All other long-term debt & preferred stock	Various companies	**2,594.7**	2,595.2	(0.5)	Normal payments/redemptions
		$ 4,286.7	$ 4,928.4	$ (641.7)	

LONG TERM

The Company's total capital requirements consist of amounts for its construction programs, working capital needs and maturing debt issues. Construction expenditure levels for the energy delivery business are generally consistent from year to year.

The following table summarizes estimated long-term contractual cash obligations of the Company:

	Payment due in:						
($'s in millions)	2006	2007	2008	2009	2010	Thereafter	Total
Long-term debt	$ 568	$ 302	$ 207	$ 687	$ 357	$ 2,113	$ 4,234
Electric purchase power commitments	1,745	1,064	1,050	1,065	869	3,057	8,850
Gas supply commitments	255	114	52	5	5	10	441
Derivative swap commitments*	204	196	183	36	-	-	619
Expected pension and post-retirement trust funding**	234	N/A	N/A	N/A	N/A	N/A	234
Interest on long-term debt***	157	119	101	75	54	N/A	506
Construction expenditures****	608	N/A	N/A	N/A	N/A	N/A	608
Total contractual cash obligations	$ 3,771	$ 1,795	$ 1,593	$ 1,868	$ 1,285	$ 5,180	$ 15,492

* Forecasted, actual amounts could differ based on changes in market conditions.

** These are expected contributions to Company's pension and post-retirement benefit plans' trusts, not the minimum funding requirement.

*** Forecasted, actual amounts could differ based on changes in market conditions. Amounts beyond five years are not forecasted.

**** Budgeted amount in which substantial commitments have been made. Amounts beyond 1 year are budgetary in nature and not contractual obligations and are therefore not included.

OTHER REGULATORY MATTERS

Regional Transmission Organizations

Midwest. GridAmerica manages a range of electricity transmission operations on behalf of its three participant utilities. It is the first multi-system independent transmission company and was formed under agreements with Ameren, First Energy, Northern Indiana Public Service Company and the Midwest Independent System Operator (MISO), which was approved by FERC to operate as an RTO.

During April 2005, Ameren notified the Company's electricity transmission business and its fellow GridAmerica participants that it will withdraw from GridAmerica effective November 1, 2005. Together with FirstEnergy and Northern Indiana Public Service Company, the Company evaluated GridAmerica's viability given the current industry environment, their respective long-term corporate strategies and Ameren's departure, and ultimately agreed to cease GridAmerica operations also effective November 1, 2005.

NEW YORK PSC MATTERS

The New York PSC has issued orders that will or may have an impact on Niagara Mohawk.

Pension settlement loss

In July 2004, Niagara Mohawk obtained PSC approval that would provide rate recovery for approximately $14 million of the $30 million pension settlement loss incurred in fiscal 2003. In addition, the agreement covers the funding of the entire settlement loss to benefit plan trust funds. Niagara Mohawk has filed a petition with the PSC seeking recovery of a $21 million pension settlement loss incurred in fiscal year 2004. For further discussion of the settlement losses see Footnote G – "Employee Benefits" of the Consolidated Financial Statements.

Pension and post-retirement benefits costs

In August 2003, the New York State PSC approved a settlement with Niagara Mohawk following an audit that identified reconciliation issues between the rate allowance and actual costs of Niagara Mohawk's pension and other post-retirement benefits. The settlement resolved all issues associated with those obligations for the period prior to its acquisition by National Grid and, among other things, covered the funding of Niagara Mohawk's pension and post-retirement benefit plans. As part of the settlement, Niagara Mohawk provided $100 million of tax-deductible funding by the end of fiscal 2003 and an additional $209 million of tax-deductible funding by the end of fiscal 2004. Under the settlement, Niagara Mohawk will earn a rate of return of at least 6.60 percent (nominal) on the $209 million of funding through December 31, 2011 and is eligible to earn 80 percent of the amount by which the rate of return on the pension and post-retirement benefit funds exceeds 5.34 per cent (nominal) measured as of that date.

Elevated equipment voltage

The PSC issued an order on January 5, 2005, requiring all electric utilities in the state to test annually all of their publicly accessible transmission and distribution facilities for elevated equipment voltage and perform visual inspections of all facilities on a five-year schedule. The order contains strict compliance requirements and potential financial penalties for failure to achieve testing and inspection targets. Failure to meet the annual target for performing tests will result in a 0.75% reduction in return on equity, as will failure to meet the annual target for inspections. The costs to comply with this order are expected to be significant. Under its existing rate plan, Niagara Mohawk is eligible to recover through rates that portion of its costs that the PSC considers incremental. Niagara Mohawk, together with other utilities, has filed for rehearing on certain aspects of this order, including a request for more time to test remote areas of the service territory, a challenge to the PSC authority to impose penalties for non-compliance, and clarification that the PSC did not intend to impose a different standard for cost recovery for these programs than is otherwise specified in Niagara Mohawk's pre-existing rate plan, among other clarifications. In February 2005, Niagara Mohawk filed plans for testing and inspections as required by the PSC and a petition to request an extended schedule to complete testing.

Wholesale supplier bankruptcy settlement

Pursuant to terms of a settlement reached in the USGen New England Inc. (USGen) bankruptcy proceeding, New England Power (NEP), on behalf of it and other NGUSA subsidiaries, received $195 million (amount received on June 8, 2005 and June 9, 2005) representing the settlement of its claims relating to (a) USGen's breach of its obligations under transferred purchased power contracts, high voltage direct current (HVDC) support contracts and indemnification obligations, (b) disputes under the standard offer supply contracts and (c) pre-bankruptcy petition obligations. As a result of the bankruptcy, USGen returned to NEP obligations it had assumed under seven power purchase contracts and the Hydro-Quebec Interconnection agreement, and terminated its indemnification for any potential site-related liabilities for generating units NEP had sold to USGen. Because costs arising from these obligations are recoverable through its contract termination charges (CTC), the settlement proceeds will be credited to the CTC. In June, NEP submitted a plan to implement such a CTC credit with the parties in Massachusetts, Rhode Island and New Hampshire. The plan provides for the $195 million to be used to pay off a portion of any unrecovered fixed stranded assets and trigger payments made under power purchase contracts, to significantly reduce the CTCs and provide for a declining CTC in the future. This plan avoids dramatic swings in the CTC that would result from crediting the entire amount of settlement proceeds through the CTC in a single year. While the state commissions do not have jurisdiction over the CTC, which is a Federal Energy Regulatory Commission (FERC) approved rate, NEP is seeking the agreement of the CTC parties before ultimately filing the plan for approval with the FERC.

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2005 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Boston, Massachusetts

May 18, 2005, except for the NEP section of Note B and the Town of Norwood Dispute section of Note C, as to which the dates are June 9, 2005 and July 22, 2005, respectively

NATIONAL GRID USA AND SUBSIDIARY COMPANIES

Consolidated Statements of Income
(In thousands of dollars)

	For the years ended March 31,		
	2005	2004	2003
Operating revenues:			
Electric	**$ 6,263,607**	$ 6,414,325	$ 6,095,355
Gas	**808,015**	779,600	708,613
Total operating revenues	**7,071,622**	7,193,925	6,803,968
Operating expenses:			
Purchased energy:			
Electricity purchased	**2,911,101**	3,145,135	2,770,256
Gas purchased	**509,543**	478,647	393,796
Contract termination and nuclear shutdown charges	**149,140**	145,517	161,583
Other operation and maintenance	**1,346,684**	1,567,866	1,515,783
Depreciation and amortization	**382,758**	375,995	378,195
Amortization of stranded costs	**318,844**	264,824	221,809
Other taxes	**322,259**	343,534	369,100
Income taxes (Note H)	**306,229**	269,667	228,729
Total operating expenses	**6,246,558**	6,591,185	6,039,251
Operating income	**825,064**	602,740	764,717
Other income (deductions), net	**5,675**	(21,085)	(37,523)
Operating and other income	**830,739**	581,655	727,194
Interest:			
Interest on long-term debt	**207,791**	263,616	370,597
Other interest	**69,250**	51,955	46,303
Total interest expense	**277,041**	315,571	416,900
Net income	**$ 553,698**	$ 266,084	$ 310,294

Consolidated Statements of Comprehensive Income
(In thousands of dollars)

	For the years ended March 31,		
	2005	2004	2003
Net income	**$ 553,698**	$ 266,084	$ 310,294
Other comprehensive income:			
Unrealized gains (losses) on securities, net of taxes	**526**	7,457	(3,885)
Hedging activity, net of taxes	**9,787**	2,425	600
Change in additional minimum pension liability, net of taxes	**(4,629)**	67,292	(249,075)
Total other comprehensive income (loss)	**5,684**	77,174	(252,360)
Comprehensive income	**$ 559,382**	$ 343,258	$ 57,934

Consolidated Statements of Retained Earnings
(In thousands of dollars)

	For the years ended March 31,		
	2005	2004	2003
Retained earnings at beginning of period	**$ 648,255**	$ 388,454	$ 317,183
Net income	**553,698**	266,084	310,294
Dividends on preferred stock	**(3,461)**	(5,095)	(6,624)
Dividends on common stock	**(218,100)**	-	(233,000)
Loss on redemption of preferred stock	**-**	(1,194)	604
Other	**(291)**	6	(3)
Retained earnings at end of period	**$ 980,101**	$ 648,255	$ 388,454

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES

Consolidated Balance Sheets

(In thousands of dollars)

	March 31, 2005	March 31, 2004
ASSETS		
Utility plant, at original cost:		
Electric plant	**$ 10,531,420**	$ 10,170,487
Gas plant	**1,517,804**	1,477,977
Common plant	**378,418**	358,341
Construction work-in-process	**175,879**	213,702
Total utility plant	**12,603,521**	12,220,507
Less: accumulated depreciation and amortization	**(3,972,348)**	(3,820,799)
Net utility plant	**8,631,173**	8,399,708
Goodwill, net of amortization	**3,237,049**	3,232,125
Pension intangible	**54,888**	26,439
Other property and investments	**412,637**	394,300
Current assets:		
Cash and cash equivalents	**354,578**	243,085
Restricted cash (Note A)	**15,288**	17,204
Accounts receivable (less reserves of $147,597 and $142,175, respectively, and includes receivables from associated companies of $6,806 and $3,431, respectively)	**1,117,729**	1,084,886
Materials and supplies, at average cost:		
Gas storage	**3,498**	11,226
Other	**42,602**	33,872
Derivative instruments	**35,326**	24,393
Prepaid taxes	**16,748**	-
Current portion of accumulated deferred income taxes Note H)	**340,837**	248,642
Current portion of regulatory assets (Note B)	**308,044**	287,011
Other	**36,381**	24,030
Total current assets	**2,271,031**	1,974,349
Other non-current assets:		
Regulatory assets (Note B)	**6,034,286**	6,330,205
Other	**70,875**	88,233
Total non-current assets	**6,105,161**	6,418,438
Total assets	**$ 20,711,939**	$ 20,445,359

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets
(In thousands of dollars)

	March 31, 2005	March 31, 2004
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stockholder's equity:		
Common stock ($.10 par value)	$ -	$ -
Authorized - 3,000 shares		
Issued and outstanding - 1,000 shares		
Additional paid-in capital	**7,099,046**	7,099,046
Retained earnings	**980,101**	648,255
Accumulated other comprehensive loss (Note D)	**(172,161)**	(177,845)
Total common stockholder's equity	**7,906,986**	7,569,456
Minority interest in subsidiaries	**19,551**	21,084
Cumulative preferred stock (Note K)	**52,317**	77,633
Long-term debt (Note I)	**2,464,058**	3,050,315
Long-term debt to affiliates (Note I)	**1,200,000**	1,200,000
Total capitalization	**11,642,912**	11,918,488
Current liabilities:		
Accounts payable	**588,200**	536,773
Customers' deposits	**34,061**	32,873
Accrued interest	**70,979**	84,912
Accrued taxes	-	14,821
Short-term debt due to affiliates	**687,168**	452,436
Current portion of long-term debt	**567,725**	597,230
Current portion of swap contracts liability	**203,558**	182,000
Current portion of purchased power obligations (Note C)	**104,486**	105,011
Other	**198,881**	193,195
Total current liabilities	**2,455,058**	2,199,251
Other non-current liabilities:		
Accumulated deferred income taxes	**2,204,833**	1,953,477
Unamortized investment tax credits	**74,331**	80,158
Accrued Yankee nuclear plant costs (Note C)	**221,540**	269,940
Purchased power obligations (Note C)	**189,126**	293,295
Liability for swap contracts (Note E)	**415,394**	533,367
Accrued employee pension and other benefits (Note G)	**607,895**	639,290
Additional minimum pension liability (Note G)	**290,145**	239,623
Environmental remediation costs (Note C)	**604,540**	418,185
Nuclear fuel disposal costs (Note C)	**145,562**	143,265
Regulatory liabilities (Note B)	**1,427,513**	1,357,543
Other	**433,090**	399,477
Total other non-current liabilities	**6,613,969**	6,327,620
Total capitalization and liabilities	**$ 20,711,939**	$ 20,445,359

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statement of Cash Flow
(In thousands of dollars)

	For the years ended March 31,		
	2005	2004	2003
Operating activities:			
Net income	**$ 553,698**	$ 266,084	$ 310,294
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**382,758**	375,995	378,195
Amortization of stranded costs	**318,844**	264,824	221,809
Provision for deferred income taxes	**220,121**	150,422	128,507
Pension and other retirement benefit plan expense	**168,689**	281,471	258,903
Cash paid to pension and other retirement benefit plan trusts	**(200,084)**	(370,823)	(214,129)
Adjustments to goodwill	**(4,924)**	(2,028)	5,325
Changes in operating assets and liabilities:			
Change in accounts receivable, net	**(32,843)**	(93,304)	30,772
Change in materials and supplies	**(1,002)**	(5,978)	3,279
Change in prepaid taxes	**(16,748)**	-	7,209
Change in accounts payable and accrued expenses	**58,301**	(105,432)	64,978
Change in accrued interest and taxes	**(28,754)**	(63,192)	40,601
Change in pension and postretirement regulatory assets	**3,472**	(5,432)	83,776
Change in purchased power obligations	**(104,694)**	(111,621)	(151,533)
Other, net	**39,589**	(6,383)	(116,313)
Net cash provided by operating activities	**1,356,423**	574,603	1,051,673
Investing activities			
Construction additions	**(592,160)**	(552,293)	(470,796)
Sale of assets	**7,649**	11,977	332,300
Change in restricted cash	**1,916**	8,399	(12,957)
Other, net	**(28,271)**	(8,050)	26,114
Net cash used in investing activities	**(610,866)**	(539,967)	(125,339)
Financing activities			
Dividends paid on preferred stock	**(3,461)**	(5,095)	(6,624)
Dividends paid on common stock	**(218,100)**	-	(233,000)
Dividends paid on common stock of minority interests	**(4,918)**	(3,801)	(4,097)
Reductions in long-term debt	**(669,267)**	(1,812,085)	(776,169)
Proceeds from long-term debt	**52,775**	1,659,360	-
Redemption of preferred stock	**(25,316)**	(40,495)	(1,712)
Buyback of minority interest common stock	**(6,730)**	(3,454)	(3,717)
Net change in short-term debt to affiliates	**234,732**	273,134	106,350
Other, net	**6,221**	6	-
Net cash (used in) provided by financing activities	**(634,064)**	67,570	(918,969)
Net increase in cash and cash equivalents	**111,493**	102,206	7,365
Cash and cash equivalents, beginning of period	**243,085**	140,879	133,514
Cash and cash equivalents, end of period	**$ 354,578**	$ 243,085	$ 140,879
Supplemental disclosures of cash flow information:			
Interest paid	**$ 285,578**	$ 366,489	$ 404,588
Taxes paid	**108,129**	188,608	13,585

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A - SIGNIFICANT ACCOUNTING POLICIES

1. Nature of Operations:
National Grid USA (the Company) is a public utility holding company headquartered in Westborough, Massachusetts. The Company's regulated subsidiaries are engaged in the transmission, distribution, and sale of electricity and natural gas. The Company's electricity and gas distribution subsidiaries serve approximately 3.9 million customers in New York State, Massachusetts, Rhode Island and New Hampshire. The Company's transmission subsidiaries provide electricity transmission in New York through Niagara Mohawk Power Corporation (Niagara Mohawk) and in New England principally through New England Power Company (NEP) and The Narragansett Electric Company. In addition, in the Midwest, GridAmerica manages a range of electricity transmission operations on behalf of its three participant utilities. Effective November 1, 2005, GridAmerica will cease operations. Unregulated subsidiaries are engaged in the construction and leasing of telecommunications infrastructures and energy-related consulting.

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 transmission, distribution and gas operations (regulated subsidiaries), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities having jurisdiction (see below).

The consolidated financial statements include the accounts of the Company and all of its wholly-owned subsidiaries and minority interests. All intercompany transactions and balances between consolidated subsidiaries have been eliminated.

National Grid USA owns approximately 53.7 percent of the outstanding common stock of both New England Hydro Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation (together, the Hydro Transmission companies). The Hydro-Transmission companies own and operate an international transmission interconnection between Hydro-Quebec and New England. The consolidated financial statements include 100 percent of the assets, liabilities, and earnings of the Hydro Transmission companies. Minority interests, which represent the minority stockholders' proportionate share of the equity and income of the Hydro Transmission companies, have been separately disclosed on the National Grid USA consolidated balance sheets and statements of income.

NEP has a minority ownership interest in each of three regional nuclear generating companies which own generating facilities which are permanently shut down. NEP accounts for these ownership interests under the equity method.

3. Use of Estimates:
In preparing the financial statements, management is required to make estimates that affect the reported amounts of assets and liabilities and disclosures of asset recovery and contingent 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. Regulation:
The Company's regulated subsidiaries and certain unregulated subsidiaries are subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935, as amended (PUHCA). The regulated subsidiaries must also comply with the rules prescribed by the Federal Energy Regulatory Commission (FERC) and the applicable state utility commissions of New York, Massachusetts, Rhode Island and New Hampshire. See Note B – "Rate and Regulatory Issues." NEP and Niagara Mohawk, file reports with the SEC under the Securities Exchange Act of 1934, as amended.

5. Goodwill:

The acquisition of the Company by National Grid Transco (NGT), and the subsequent acquisitions by the Company of Eastern Utilities Associates (EUA) and Niagara Mohawk, were accounted for by the purchase method, the application of which includes the recognition of goodwill. Goodwill was approximately $3.2 billion at March 31, 2005 and 2004, respectively. In accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangible Assets”, the Company reviews its goodwill annually for impairment and when events or circumstances indicate that the asset may be impaired. The Company utilized a discounted cash flow approach incorporating its most recent business plan forecasts in the performance of the annual goodwill impairment test. Upon the annual analysis at March 31, 2005, management determined that no adjustment to the goodwill carrying value was required.

6. Electric and Gas Utility Revenue:

The Company’s regulated subsidiaries charge customers for electric and gas service in accordance with rates approved by the FERC and the applicable state regulatory commissions.

All of the Company’s distribution subsidiaries, except for Granite State Electric, follow the policy of accruing the estimated amount of base rate revenues for electricity delivered but not yet billed (unbilled revenues), to match costs and revenues more closely. The distribution subsidiaries record revenues in amounts management believes to be recoverable pursuant to provisions of approved settlement agreements and state legislation. The distribution subsidiaries normalize the difference between revenue and expenses from energy conservation programs, commodity purchases, transmission service and contract termination charges (CTCs). The unbilled revenue included in accounts receivable at March 31, 2005 and 2004 was approximately $154 million and $169 million, respectively.

Pursuant to Niagara Mohawk’s 2000 multi-year gas settlement (ending December 2004), changes in accrued unbilled gas revenues are deferred. At March 31, 2005 and 2004, approximately $7 million and $9 million, respectively, of unbilled gas revenues remain unrecognized in results of operations. Niagara Mohawk cannot predict when unbilled gas revenues will be allowed to be recognized in results of operations.

7. Utility Plant:

The cost of additions to utility plant and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead and AFUDC (see 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.

8. Allowance for Funds Used During Construction (AFUDC):

The utility subsidiaries capitalize AFUDC as part of construction costs. 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 "Utility plant" with offsetting non-cash credits to “Other income” and “Interest.” This method is in accordance with an established rate making practice under which a utility is permitted 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 approximately 4.8 percent, 4.5 percent and 4.1 percent for the years ended March 31, 2005, 2004 and 2003, respectively.

9. Depreciation and Amortization:
Depreciation expense is determined using the straight-line method. The depreciation rates for the regulated 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 regulated subsidiaries use composite depreciation rates that are approved by the respective state utility commissions. The average depreciation rates for Property, Plant, and Equipment, by business segment, are presented in the table below.

	Average Rate		
Business Segment	**2005**	**2004**	**2003**
Electricity distribution	3.53%	3.55%	3.62%
Electricity transmission	2.56%	2.69%	2.67%
Gas distribution	2.48%	2.49%	2.59%
Other	4.69%	4.62%	4.21%

Regulatory assets, including those covered by CTCs, 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 – "Rate and Regulatory Issues"). Niagara Mohawk's costs are being amortized unevenly over ten years with larger amounts being amortized in the latter years, consistent with projected recovery through rates.

10. 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 hedging activity, health care claims deposits, New York State Department of Conservation securitization for certain site cleanup, and a worker's compensation premium deposit.

Under the Loan and Trust Agreement for the Massachusetts Development Finance Agency Tax Exempt Electric Utility Revenue Bonds (Nantucket Electric Company Issue), Series 2004A (the Bonds), the Company established a Construction Fund with the Trustee in which the proceeds from the Bonds were deposited. The $10 million deposited was to fund the Second Nantucket Cable Project costs. Disbursements from the Construction Fund may be made by the Trustee to pay directly or to reimburse the Company for eligible project costs as directed by requisitions signed by the Company. At March 31, 2005, the Company used $5.8 million of the funds deposited. This requisition process is the only manner in which project costs may be paid from Bond proceeds.

12. Income Taxes:
Income taxes have been computed utilizing the asset and liability approach, which requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences. It does this 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 (see Note H – "Income Taxes").

13. Derivatives:

The Company accounts for derivative financial instruments under SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (FAS 133), and SFAS No. 149, "Amendment of SFAS No. 133 on Derivative Instruments and Hedging Activities," as amended. Under the provisions of FAS 133, all derivatives except those qualifying for the normal purchase/normal sale exception are recognized on the balance sheet at their fair value. Fair value is determined using current quoted market prices. If a contract is designated as a cash flow hedge, the change in its market value is generally deferred as a component of other comprehensive income until the transaction it is hedging is completed. Conversely, the change in the market value of a derivative not designated as a cash flow hedge is deferred as a regulatory asset or liability. A cash flow hedge is a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. To qualify as a cash flow hedge, the fair value changes in the derivative must be expected to offset 80% to 120% of the changes in fair value or cash flows of the hedged item.

The Company has received approval from the New York State Public Service Commission (PSC) to establish a regulatory asset or liability for derivative instruments that did not qualify for hedge accounting and were the result of regulatory rulings.

14. 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, the other components of comprehensive income (loss) relate to additional minimum pension liability recognition, 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. Additional minimum pension liability:

NEP and Niagara Mohawk recover all costs associated with their qualified pension plans and therefore do not recognize the additional minimum pension liability (AML) for their qualified plans as a component of accumulated other comprehensive income, but instead as a regulatory asset.

16. New Accounting Standards

FAS 123-R

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." This Standard addresses the accounting for transactions in which a company receives employee services in exchange for (a) equity instruments of the company or (b) liabilities that are based on the fair value of the company's equity instruments or that may be settled by the issuance of such equity instruments. This Standard also eliminates the ability to account for share-based compensation transactions using Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and requires that such transactions be accounted for using a fair-value-based method. The Standard is effective for fiscal years beginning after June 15, 2005. The adoption of this statement will not have a material impact on the Company's financial position, results of operations, or cash flows.

FIN 47

In March 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 will result in (a) more consistent recognition of liabilities relating to asset retirement obligations, (b) more information about expected future cash outflows associated with those obligations and (c) more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets.

FIN 47 clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, "Accounting for Asset Retirement Obligations", 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 entity. The obligation to perform the asset retirement activity is unconditional even though the uncertainty exists about the timing and (or) method of settlement. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

This statement will be effective for the fiscal year ended March 31, 2006 for the Company. The adoption of FIN 47 is not expected to have a material impact on the Company's results of operations or its financial position.

FSP 106-2

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expands Medicare, primarily by adding a prescription drug benefit for Medicare-eligibles starting in 2006. The Act provides employers currently sponsoring prescription drug programs for Medicare-eligibles with a range of options for coordinating with the new government-sponsored program to potentially reduce program cost. These options include supplementing the government program on a secondary payor basis or accepting a direct subsidy from the government to support a portion of the cost of the employer's program.

Paragraph 40 of the SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (FAS 106) requires that presently enacted changes in laws impacting employer-sponsored retiree health care programs which take effect in future periods be considered in current-period measurements for benefits expected to be provided in those future periods. Therefore, under FAS 106 guidance, measures of plan liabilities and annual expense on or after the date of enactment should reflect the effects of this Act.

Reclassifications

Certain amounts from prior years have been reclassified on the accompanying consolidated financial statements to conform to the fiscal 2005 presentation.

NOTE B – RATE AND REGULATORY ISSUES

The Company's regulated subsidiaries generally use the same accounting policies and practices for financial reporting purposes as non-regulated companies under US GAAP. However, actions by the FERC and the state utility commissions can result in accounting treatment that is different from that used by non-regulated companies. The Company applies the provisions of the SFAS No. 71, "Accounting for Certain Types of Regulation" (FAS 71). In accordance with FAS 71, the Company's regulated subsidiaries record regulatory assets (expenses deferred for future recovery from customers) and regulatory liabilities (amounts provided in current rates to cover costs to be incurred in the future) on their balance sheets. This permits the regulated subsidiaries to defer certain costs (because they are expected to be recovered through customer billings) and revenues (because they are expected to be refunded to customers), which would otherwise be charged to expense or revenue, when authorized to do so by the regulator. In aggregate, the Company's regulated subsidiaries had approximately $6.3 billion and $6.6 billion of regulatory assets at March 31, 2005 and 2004, respectively.

The following table details the various categories of regulatory assets and liabilities:

($'s in 000's)	At March 31, 2005	2004
Regulatory assets:		
Stranded costs	$ 2,997,281	$ 3,251,391
Purchased power	382,955	549,019
Swap contract costs	415,394	533,367
Regulatory tax asset	120,521	195,411
Deferred environmental restoration costs	594,283	395,960
Pension and postretirement benefit plans costs	531,366	517,074
Additional minimum pension liability (see Note G)	252,218	237,286
Yankee nuclear plant costs	221,540	269,940
Loss on reacquired debt	87,645	96,333
LT portion of standard offer under-recovery	42,420	-
Other	388,663	284,424
Total non-current regulatory assets	6,034,286	6,330,205
Current portion of swap contract costs	203,558	182,000
Current portion of purchase power buyout costs	104,486	105,011
Total current portion of regulatory assets	308,044	287,011
Total regulatory assets	$ 6,342,330	$ 6,617,216
Regulatory liabilities:		
Cost of removal reserve (see Note L)	$ (504,819)	$ (487,040)
Stranded costs and CTC related	(209,291)	(246,914)
Pension and postretirement plans fair value deferred gain	(228,138)	(243,185)
Interest savings deferral	(92,534)	(92,534)
Environmental response fund and insurance recoveries	(82,012)	(80,253)
Storm costs reserve	(33,681)	(27,244)
Other	(277,038)	(180,373)
Total regulatory liabilities	$ (1,427,513)	$ (1,357,543)

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. For the New England regulated subsidiaries, this mechanism is called the Contract Termination Charge and for Niagara Mohawk in New York, it is called 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 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. In the event of revenues that are lower than expected and/or costs that are higher than expected, if the Company determines that its net regulatory assets are not probable of recovery, it can no longer apply the principles of FAS 71 and would be required to record an after-tax, non-cash charge against income for any remaining unamortized regulatory assets and liabilities. If the Company's subsidiaries could no longer apply FAS 71, the resulting charge would be material to the Company's reported financial condition and results of operations.

Rate Agreements:

NEP

New England Regional Transmission Organization (RTO) and Rate Filing: New England Power Company (NEP) is a participating transmission owner (PTO) in New England's regional transmission organization (RTO) which commenced operations effective February 1, 2005. ISO New England, Inc. (ISO) has been authorized by FERC to exercise the operations and system planning functions required of RTOs and will be the independent regional transmission provider under the ISO Open Access Transmission Tariff (ISO-OATT). The ISO-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 two orders in 2004 and two in 2005 that approved the establishment of the RTO and resolved certain issues concerning the proposed ROE for New England PTOs. Other return issues were set for hearing. A number of parties, including NEP, have filed appeals from one or more of those orders with the US Court of Appeals for the District of Columbia Circuit.

NEP's currently allowed ROE for transmission assets is 10.25%. Effective on the RTO operations date of February 1, 2005, NEP's transmission rates began to reflect a proposed base return on equity of 12.8%, subject to refund, plus the additional 0.5% incentive return on regional network service (RNS) rates that FERC approved in March 2004. Approximately 70% of the Company's transmission costs are recovered through RNS rates. An additional 1.0% incentive adder is also applicable to new RNS transmission investment, subject to refund.

NEP and the other PTOs participated in FERC proceedings to determine outstanding ROE issues, including base return on equity (ROE) and the proposed 1% ROE incentive for new transmission investment. On May 27, 2005, the administrative law judge issued an initial decision which concluded that the base ROE should be 10.72% and that NEP and other PTOs are not entitled to the proposed 1% ROE incentive. All parties will have the opportunity to file a brief on exceptions in response to the judge's initial decision. A final FERC order is expected by year end 2005.

As a result of applying FAS 71, NEP has recorded a regulatory asset for the costs that are recoverable from customers through the CTC. At March 31, 2005, this amounted to approximately $0.9 billion, including approximately $0.5 billion related to the above market costs of purchased power contracts, approximately $0.2 billion related to accrued Yankee nuclear plant costs, and approximately $0.2 billion related to other net CTC regulatory assets.

When it divested its generating business, NEP transferred its entitlement to power procured under several long term contracts (the Contracts) to USGen New England, Inc. (USGen), Constellation Power Source, Inc. and TransCanada Power Marketing Ltd. (collectively the Buyers). The Buyers agreed to fulfill NEP's performance and payment obligations under the Contracts. At the same time NEP agreed to pay the Buyers a fixed amount for the above-market cost of the Contracts. (The contract transferring Contracts to Constellation Power Source has since been terminated because it was fully performed in accordance with its terms. NEP has since resumed performance and payment obligations under the Contracts that were transferred to USGen, as described in the paragraph below.) These fixed payments by NEP were $91 million and $92 million for fiscal years 2005 and 2004, respectively. The net present value of these fixed monthly payments is recorded as a liability with an equal balance recorded in regulatory assets representing the future collection of the liability from ratepayers. At March 31, 2005 and 2004, the net present value of the liability for the fixed monthly payments is approximately $294 million and $398 million, respectively.

USGen had previously filed for bankruptcy protection on July 8, 2003. NEP reached a settlement with USGen regarding all matters between the parties, which was approved by the bankruptcy court on December 22, 2004. Under the settlement, on April 1, 2005, the agreement by which NEP transferred the Contracts to USGen was terminated. NEP resumed the performance and payment obligations under the Contracts that had been transferred to USGen and removed the related liability and offsetting regulatory asset for the above market portion of the Contracts with USGen for approximately $246 million. NEP continues to record a derivative liability of $404 million for the above market portion of the contracts with an equal offset to a corresponding regulatory asset. The performance and payment obligations will not materially affect the results of operations, as NEP will recover the above-market cost of the Contracts from customers through the CTC. In accordance with the settlement, NEP received proceeds of approximately $195.8 million on June 8, 2005 and June 9, 2005 from USGen. That amount relates in part to the Contracts and NEP has filed a plan with regulators to credit the $195.8 million to customers through the CTC.

The settlement between NEP and USGen also resolved the Company's claims with respect to the Hydro Quebec transmission line agreements (HQ Transmission Line Agreements), under which USGen was obligated to reimburse NEP for monthly costs of approximately $1 million. As of April 2, 2004, NEP resumed performance and payment under the HQ Transmissions Line Agreements. NEP's resumption of performance and payment obligations has not affected the results of operations, as NEP is recovering any remaining costs of the HQ Transmission Line Agreements from its customers through the CTC. The payment received from USGen relates in part to the HQ Transmission Line Agreements and NEP has filed a plan with the regulators for it to credit the $195.8 to customers through the CTC.

Niagara Mohawk

Niagara Mohawk's distribution and transmission rates are regulated by the New York Public Service Commission (PSC) and FERC. As part of the regulatory approval process for the acquisition of Niagara Mohawk, a 10-year rate plan was approved by the PSC which became effective on January 31, 2002. Electricity delivery rates were reduced by $152 million and are subject to only limited adjustments for a period of 10 years. However, Niagara Mohawk will continue to be able to adjust rates to recover the cost to procure power for customers. Under the plan, rates were designed so that Niagara Mohawk may earn a return on equity of up to 10.6% after reflecting its share of savings related to the acquisition. Niagara Mohawk is also allowed to earn up to 12.0% if certain customer education targets are met, and half of any earnings in excess of that amount. Returns above 11.75% are then subject to a sharing mechanism with customers.

Under the plan, gas delivery rates were frozen until the end of the 2004 calendar year, and Niagara Mohawk now has the right to request an increase at any time, if needed. Under the plan, rates were designed so that Niagara Mohawk may earn a threshold ROE of up to 10.6%. Niagara Mohawk is also allowed to earn up to 12.0% if certain customer migration and education goals are met, and is required to share earnings above this threshold with customers.

Massachusetts Electric Company and Nantucket Electric Company

Under Massachusetts Electric's long-term rate plan, there is no cap on earnings and no earnings sharing mechanism until 2010. From May 2000 until February 2005, rates were frozen. In March 2005, a settlement credit in the company's rates expired, which represents an increase of $10 million through February 2006. From March 2006, rates will be adjusted each March until 2009 by the annual percentage change in average unbundled electricity distribution rates in the northeastern US. In 2010, actual earned savings will be determined and the company will be allowed to retain 100% of annual earned savings up to $70 million and 50% of annual earned savings between $70 million and $145 million (all figures pre-tax). Earned savings represents the difference between calendar year 2008 distribution revenue and the company's cost of providing service, including a regional average authorized return. These efficiency incentive mechanisms provide an opportunity to achieve returns in excess of traditional regulatory allowed returns. Massachusetts Electric will be allowed to include its share of earned savings in demonstrating its costs of providing service to customers from January 2010 until May 2020.

In December 2004, the Massachusetts Department of Telecommunications and Energy (MDTE) approved a comprehensive settlement agreement between Massachusetts Electric, its wholesale affiliate, NEP, and the Massachusetts Attorney General, which addressed contract termination charges from NEP to the Company as well as the recovery of certain supply-related costs. For the Company, the settlement provided for (i) deferred rate recovery of about $66 million of power supply-related costs (of which $40.5 million has been recognized on the balance sheet at March 31, 2005), with interest, until 2010 and (ii) one-time customer credits of about $10 million, reflecting $8.5 million of reduced costs due to recent federal tax law changes and $1.4 million to reflect increased supply costs resulting from reclassifying certain customers from default service to standard offer service. For NEP, the settlement resolved a broad range of outstanding wholesale rate issues, including the reasonableness of the proceeds from the litigation and sale associated with the NEP settlement on the Millstone 3 nuclear generating unit, for a settlement credit of about $10 million.

Nantucket Electric's distribution rates are linked to Massachusetts Electric's rates and became effective on May 1, 2000.

The Narragansett Electric Company

In Rhode Island, Narragansett Electric's distribution rates are governed by a long-term rate plan. Between May 2000 and the end of October 2004, rates were frozen and it was permitted to retain

100% of its earnings up to an allowed return on equity of 12%. Narragansett kept 50% of earnings between 12% and 13%, and 25% of earnings in excess of 13%. In effect from November 2004 until December 2009, Narragansett Electric has agreed to freeze its rates after an initial reduction of $10.2 million. Beginning in January 2005, it will be able to keep an amount equal to 100% of its earnings up to an allowed return on equity of 10.5%, plus $4.65 million (pre-tax), which represents its share of earned savings. Earnings above that amount up to an additional 1% return on equity are to be shared equally between Narragansett and its customers, while additional earnings will be allocated 75% to customers and 25% to Narragansett.

Granite State Electric Company
The current rates for Granite State Electric are subject to regulation by the New Hampshire Public Utilities Commission and became effective in July 1998.

NOTE C – COMMITMENTS AND CONTINGENCIES

Environmental issues:
The normal ongoing operations and historic activities of Niagara Mohawk, Massachusetts Electric, Narragansett Electric, Granite State Electric and NEP are subject to various federal, state and local environmental laws and regulations. Like most other industrial companies, our transmission and distribution companies use or generate a broad range of hazardous materials. 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.

Federal and state environmental regulators, as well as private parties, have alleged that our transmission and distribution companies are potentially responsible parties under Superfund for the remediation of over 180 contaminated sites in New England and New York, and for resulting damages. Our greatest potential Superfund liabilities relate to former manufactured gas plant, or MGP, facilities formerly owned or operated by our subsidiaries or their predecessors from the mid 1800s until the divestiture of generation assets in the mid 1990s. MGP byproducts included fuel oils, hydrocarbons, coal tar, purifier waste and other waste products that may pose a risk to human health and the environment. We are investigating or remediating these sites, or both, as appropriate.

We believe that our ongoing operations and our response to the impact of our historic operations are in substantial compliance with environmental laws, and that the obligations imposed on us are not likely to have a material adverse impact on our financial condition or results of operations because we recover a majority of these costs under our rate plans. We are pursuing claims against insurance carriers and potentially responsible parties to recover investigation and remediation costs, but we cannot predict the success of such claims. To the extent that prudently incurred costs cannot be recovered through insurance or otherwise, these are recoverable under applicable rate plans. As of March 31, 2005 and 2004, the Company has recorded an obligation of $605 million and $418 million, respectively, along with an offsetting regulatory asset, on its balance sheet. The increase in the liability follows a recent review and reflects experience by the National Grid Companies in restoring similar sites. The potential high end of the range at March 31, 2005 is presently estimated at approximately $632 million.

Decommissioning Nuclear Units:
NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, and Maine Yankee Atomic Power Company (together, the Yankees). These ownership interests are accounted for on the equity method. The Yankees own nuclear generating units that have been permanently retired and are conducting decommissioning operations. The three units are as follows:

	NEP's Equity Investment as of March 31, 2005			Future Estimated
Nuclear Unit	% Ownership	$ (millions)	Date Retired	Billings to NEP $ (millions)
Yankee Atomic	34.5	0.3	February 1992	37
Connecticut Yankee	19.5	8.7	December 1996	118
Maine Yankee	24.0	8.7	August 1997	67

With respect to each of these units, NEP has 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 NEP. The Company's share of the decommissioning costs is accounted for in "Purchased energy" on the income statement. Under settlement agreements, NEP is permitted to recover prudently incurred decommissioning costs through CTCs.

The Yankees are periodically required to file rate cases, presenting the Yankees' estimates of future decommissioning costs for FERC approval. Yankee Atomic and Maine Yankee are currently collecting decommissioning and other costs under FERC Orders issued in their respective rate cases. Connecticut Yankee is also collecting costs, subject to refund under a rate case now pending at the FERC, as described below.

Future estimated billings from the Yankees are based on decommissioning cost estimates. These estimates include the projected costs of decontaminating the units as required by the Nuclear Regulatory Commission, dismantling the units, 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 Department of Energy's obligation to remove the fuel as required by the Nuclear Waste Policy Act of 1982. A trial at the U.S. Court of Federal Claims to determine the level of damages has concluded and the parties are awaiting an order. Any damages received by the Yankees would be applied to reduce the decommissioning and other costs collected from their purchasers. 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 filed with the FERC seeking 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 amounts to approximately $396 million through 2010, NEP's share of which is included in the future estimated billings shown in the table above. The rate case also reflects the impact of the termination of a fixed price contract with Bechtel Power Corporation to perform decommissioning operations and projects a substantial increase in costs over and delay in completion compared with those previously projected.

The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel (together, the Department) have intervened at the FERC requesting that the FERC reject Connecticut Yankee's rate filing, or in the alternative, disallow a portion of the requested rate increase on the ground that $205 million to $235 million of these costs were imprudently incurred. Bechtel and three New England states have also intervened, asserting that these costs are imprudent and should be disallowed. FERC authorized Connecticut Yankee to begin charging the proposed new rates effective February 1, 2005, subject to refund. Hearings on the rate increase filing at FERC were held in June, initial briefs are due in September, and an initial decision is due in December.

Prior to Connecticut Yankee's filing, the Department petitioned the FERC to determine that Connecticut Yankee's purchasers, including NEP, were obliged to pay for all of Connecticut Yankee's decommissioning costs, whether or not prudent, and could not pass on any imprudent costs to their retail customers. The FERC denied the petition on the ground that it has no jurisdiction over retail rates. The Department and Bechtel moved for clarification and rehearing. FERC has not yet ruled on this motion.

Connecticut Yankee and Bechtel are litigating the termination of the fixed price contract in Connecticut state court, with each party seeking substantial damages. Trial is scheduled to commence in mid-2006.

Divested Nuclear Units:

Nine Mile Point: On November 7, 2001, Niagara Mohawk sold its nuclear assets to Constellation Energy Group (Constellation). As of March 31, 2005, Niagara Mohawk has a liability of $146 million for the disposal of nuclear fuel irradiated prior to 1983. 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 Niagara Mohawk'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 Niagara Mohawk has elected to delay payment, with interest, until the year in which Constellation 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.

Millstone 3 Prudence Challenge: In November 1999, NEP agreed with Northeast Utilities (NU) to settle certain claims. As part of the agreement, NU agreed to include NEP's 16.2 percent ownership interest in Millstone Unit 3 in an auction of NU's share of the unit. Upon the closing of the sale, NEP was to receive a fixed amount, regardless of the actual sale price. In March 2001, the Millstone units were sold, including NEP's interest, for $1.3 billion. In accordance with the settlement, NEP was paid approximately $25 million for its interest in the unit (plus reimbursement of pre-paid amounts), from which NEP paid approximately $6.2 million to increase the decommissioning trust fund.

In the past, regulatory authorities from Rhode Island, New Hampshire and Massachusetts expressed intent to challenge the reasonableness of the settlement agreement on various grounds, taking the position that NEP would have received approximately $140 million of sale proceeds if there had been no agreement with NU. The matter has been resolved in New Hampshire and Massachusetts. In the event that Rhode Island proceeds with a challenge, the dispute will be resolved by the FERC. Management believes that the Company acted prudently because, among other reasons, the amount it received under the settlement agreement was the highest sale price for a nuclear unit at the time the agreement was reached.

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. The Company's commitments under these long-term contracts, as of March 31, 2005, are as follows:

(In millions of dollars)

Fiscal Year Ended March 31,		Amount
2006	$	1,745
2007		1,064
2008		1,050
2009		1,065
2010		869
Thereafter		3,057
Total	$	8,850

If the Company's subsidiaries need any additional energy to meet load requirements, they can purchase the electricity from other IPPs, other utilities, other energy merchants or the open market through the New York Independent System Operator (NYISO) or the New England Independent System Operator (ISO –NE) at market prices.

Gas Supply, Storage and Pipeline Commitments:

In connection with its regulated gas business, Niagara Mohawk has long-term commitments with a variety of suppliers and pipelines to purchase gas commodity, provide gas storage capability and transport gas commodity on interstate gas pipelines.

The table below sets forth the Company's estimated commitments at March 31, 2005, for the next five years, and thereafter (dollars in millions).

Fiscal Year Ended March 31,		Amount
2006	$	255
2007		114
2008		52
2009		5
2010		5
Thereafter		10
Total	$	441

With respect to firm gas supply commitments, the amounts are based upon volumes specified in the contracts giving consideration for the minimum take provisions. Commodity prices are based on New York Mercantile Exchange quotes and reservation charges, when applicable. Storage and pipeline capacity commitments' amounts are based upon volumes specified in the contracts, and represent demand charges priced at current filed tariffs. At March 31, 2005, Niagara Mohawk's firm gas supply commitments have varying expiration dates, the latest of which is November 2006. The gas storage and transportation commitments have varying expiration dates with the latest being October 2012.

Commodity Reconciliations: As part of Niagara Mohawk's ongoing reconciliation of commodity costs and revenues, Niagara Mohawk identified several adjustments for the period from October 1, 2001 through April 30, 2003, and included them in filings with the PSC. Specifically, Niagara Mohawk requested recovery of $36 million of commodity costs associated with the under-reconciliation of New York Power Authority (NYPA) hydropower revenues in its commodity adjustment clause, and proposed to refund $24 million associated with other revenues that were not included in the commodity adjustment reconciliation. Following the filing, the PSC Staff completed a comprehensive audit of Niagara Mohawks' commodity costs and revenues from October 1, 2001 through December 31, 2003, and the Staff and Niagara Mohawk agreed that a refund of $2.8 million should be provided to customers through that period. The PSC approved the refund on December 20, 2004.

Plant Expenditures:
The Company's utility plant expenditures are estimated to be approximately $608 million in fiscal 2006. At March 31, 2005, substantial commitments had been made relative to future planned expenditures.

Legal Matters by Entity:

Niagara Mohawk

Niagara Mohawk Power Corp. v. Huntley Power L.L.C., Dunkirk Power L.L.C. and Oswego Harbor, L.L.C. Niagara Mohawk previously owned three power plants (the Plants), which it sold to three affiliates of NRG Energy, Inc. in 1999: Huntley Power L.L.C., Dunkirk Power L.L.C. and Oswego Harbor, L.L.C. (collectively, the NRG Affiliates). Niagara Mohawk is in involved in several proceedings with the NRG Affiliates to recover bills for station service rendered to the Plants.

The most significant is a proceeding at FERC involving Niagara Mohawk's complaint against the NRG Affiliates for failure to pay station service charges Niagara Mohawk assessed under its state-approved retail tariffs. A state collection action and other proceedings have all been stayed pending the outcome of the FERC proceeding. As of March 31, 2005, the NRG Affiliates owed Niagara Mohawk approximately $43.5 million for station service. On November 19, 2004 and April 22, 2005, the FERC issued orders denying Niagara Mohawk's complaint and found that the NRG Affiliates do not have to pay state-approved retail rates for station service. Niagara Mohawk has appealed the orders to the US Court of Appeals for the District of Columbia Circuit. The Court has consolidated this appeal with the two retail bypass cases discussed below. In the event that the Court upholds the FERC's orders, the Company would seek recovery under its rate plans of the station service charges not paid by the NRG Affiliates.

Retail Bypass: A number of generators have complained or withheld payments associated with Niagara Mohawk's delivery of station service to their generation facilities, arguing that they should be permitted to bypass its retail charges. The FERC issued two orders on complaints filed by Niagara Mohawk's station service customers in December 2003, allowing two generators to net their station service electricity over a 30-day period and to avoid state-authorized charges for deliveries made over distribution facilities. A third order involving affiliates of NRG Energy, Inc. is discussed above. These orders directly conflict with Niagara Mohawk's state-approved tariffs and the orders of the PSC on station service rates. The December 2003 FERC orders, if upheld, will permit these generators to bypass Niagara Mohawk's state-jurisdictional station service charges for electricity, including those set forth in the filing that was approved by the PSC on November 25, 2003. Niagara Mohawk filed for rehearing of these orders, and the FERC denied these requests in January 2005. Niagara Mohawk has appealed the December 2003 and January 2005 orders to the U.S. Court of Appeals for the District of Columbia Circuit.

In an order dated May 10, 2004, in a related proceeding concerning the NYISO, the FERC reaffirmed its reasoning of the December 2003 orders. In so ruling, the FERC indicated that the NYISO station service order would be limited to merchant generators self-supplying their own power, and should not be interpreted to apply to self-supplying retail industrial and commercial customers that do not compete with incumbent utilities for customer load. The Company appealed the order to the Court of Appeals for the District of Columbia Circuit on July 9, 2004. The Court of Appeals has consolidated these appeals for hearing, and briefing is scheduled to be completed in January 2006.

These FERC orders have increased the risk that generators will be able to bypass local distribution company charges (including stranded cost recovery charges) when receiving service through the NYISO. Although subject to challenge by the PSC Staff and other parties, Niagara Mohawk believes that if it experiences any lost revenue attributable to retail bypass, it will be permitted to recover these lost revenues under its Merger Rate Plan.

New England Power:

Town of Norwood Dispute: From 1983 until 1998, NEP was the wholesale power supplier for Norwood. 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 has been assessing Norwood a CTC. Norwood made a payment of approximately $20 million in July 2004. NEP and Norwood are engaged in litigation and at the FERC, as follows.

State Collection Action: NEP filed a collection action in Massachusetts Superior Court (Worcester County) to collect the CTC, which Norwood has refused to pay, apart from the initial payment in 2004. In March 2001, the Superior Court ruled that Norwood has breached the agreement by not paying the CTC charge, and ordered Norwood to make regular and substantial payments to an escrow account. Following unsuccessful appeals by Norwood, the Superior Court entered judgment for NEP on June 9, 2004 in the amount of approximately $43.3 million, based on amounts owed through January 31, 2001. Norwood continues to contest the judgment in the Superior Court and in the Massachusetts Appeals Court.

FERC 206 Proceeding: In December 2002, Norwood challenged the CTC rate with the FERC under Section 206 of the Federal Power Act, which permits the FERC to make prospective adjustments to filed rates. On June 9, 2004, the FERC administrative law judge issued an initial decision recommending that FERC revise the CTC formula to reduce the CTC amount that NEP previously calculated under the formula that FERC accepted and approved in 1998. NEP challenged this initial decision, arguing that no reduction is appropriate. Norwood and the FERC staff challenged the initial decision, arguing that the reduction is insufficient.

On July 22, 2005, the FERC issued an order agreeing with NEP's calculation of the CTC, but disagreeing with NEP's calculation of interest due on unpaid bills. NEP intends to seek rehearing on the interest determination, but will readjust its billing in accordance with FERC's order pending rehearing. As of July 2005, Norwood owes NEP approximately $50 million, as calculated under FERC's recent order.

NOTE D – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

(in 000's)	Unrealized Gains and (Losses) on Available-for-Sale Securites	Additional Minimum Pension Liability Adjustment	Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)
March 31, 2003	$ (4,115)	$ (251,504)	$ 600	$ (255,019)
Other comprehensive income (loss):				
Unrealized gains on securities, net of taxes	7,457			7,457
Hedging activity, net of taxes			2,425	2,425
Change in additional minimum pension liability, net of taxes		67,292		67,292
March 31, 2004	3,342	(184,212)	3,025	(177,845)
Other comprehensive income (loss):				
Unrealized gains on securities, net of taxes	526			526
Hedging activity, net of taxes			9,787	9,787
Change in additional minimum pension liability, net of taxes		(4,629)		(4,629)
March 31, 2005	$ 3,868	$ (188,841)	$ 12,812	$ (172,161)

Taxes on other comprehensive income for the following periods were (in thousands of $'s):

	For the year ended March 31, 2005	For the year ended March 31, 2004	For the year ended March 31, 2003
Unrealized gain/(losses) on securities	$ 351	$ 4,972	$ (2,590)
Hedging activities	6,525	1,617	452
Change in additional minimum pension liability	$ (3,086)	$ 45,527	$ (165,752)

NOTE E – DERIVATIVES AND HEDGING ACTIVITIES

In the normal course of business, Niagara Mohawk is a party to derivative financial instruments (derivatives) 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 Niagara Mohawk's overall financial risk-management policy. At the core of the policy is a condition that Niagara Mohawk 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. Niagara Mohawk does not issue or intend to hold derivative instruments for speculative trading purposes. Derivatives are accounted for according to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (FAS 133), which requires derivatives to be reported at fair value as assets or liabilities on the balance sheet. Changes in the fair value of instruments that qualify for hedge accounting are deferred in Accumulated Other Comprehensive Income and will be reclassified through purchased electricity or gas expense in the hedge months. Niagara Mohawk's rate agreements allow for the pass-through of the commodity costs of electricity and natural gas, including the costs of the hedging programs.

Niagara Mohawk has eight indexed swap contracts, expiring in June 2008 that resulted from the Master Restructuring Agreement (MRA). These derivatives are not designated as hedging instruments and are covered by regulatory rulings that allow the gains and losses to be recorded as regulatory assets or regulatory liabilities. As of March 31, 2005 Niagara Mohawk has recorded liabilities of $619 million versus $715.4 million at March 31, 2004 for these swap contracts and has recorded a corresponding swap contracts regulatory asset. The asset and liability are amortized over the remaining term of the swaps as nominal energy quantities are settled and are adjusted as periodic reassessments are made of energy price forecasts.

At March 31, 2005, management projects that Niagara Mohawk will make the following payments in connection with its swap contracts for the fiscal years 2006 through 2008, subject to changes in market prices and indexing provisions:

Year Ended March 31,	Projected Payment *(in thousands of dollars)*
2006	$ 203,558
2007	196,324
2008	182,834
2009	36,236
	$ 618,952

Niagara Mohawk uses New York Mercantile Exchange (NYMEX) gas futures to hedge the gas commodity component of its indexed swap contracts. These instruments, as used, do not qualify for hedge accounting status under SFAS 133. Cash flow hedges that are qualified under SFAS 133 are as follows: NYMEX gas futures for the purchases of natural gas and NYMEX electric swap contracts hedging the purchases of electricity.

The following table represents the open positions at March 31, 2005 and the results on operations of these instruments for the year ended March 31, 2005.

	(in thousands of dollars)				
	Balances as of March 31, 2005				**Year Ended**
Derivative Instrument	**Asset***	**Regulatory Deferral**	**Accumulated OCI**, net of tax**	**Accumulated Deferred Income Tax on OCI****	**March 31, 2005 Gain/(Loss) Reclass to Commodity Costs**
Qualified for Hedge Accounting					
NYMEX futures - gas supply	$ 7,233.4	$ -	$ (11,861.7)	$ (7,907.8)	$ 7,950.1
NYMEX electric swaps - electric supply	$ 1,067.4	$ -	$ (950.3)	$ (633.5)	$ 43.3
Non-qualified for Hedge Accounting					
NYMEX futures - IPP swaps/non-MRA IPP	$ 27,019.7	$ (29,865.8)	$ -	$ -	$ 19,376.6

* Differences between asset/(liability) and regulatory or OCI deferral represent contracts settled for the following month.

** Other comprehensive income (OCI)

At March 31, 2004, Niagara Mohawk recorded a deferred gain on the futures contracts hedging the IPP swaps and non-MRA IPP of $21.5 million, offset by the balance sheet item "Derivative Instruments" for $20.3 million with the resulting $2.1 having settled through cash for the hedge month of April 2004. For the twelve months ended March 31, 2004 settlement of NYMEX futures contracts resulted in a decrease to purchased power expense of $17.3 million.

The gains and losses on the derivatives that are deferred and reported in accumulated other comprehensive income will be reclassified as purchased energy expense in the periods in which expense is impacted by the variability of the cash flows of the hedged item. For the twelve months ended March 31, 2005, the net gain of $8 million from hedging instruments, as shown in the table above, was recorded to gas purchases offset by a corresponding increase in the cost of a comparable amount of gas. For the twelve months ended March 31, 2004, a net loss of $4.2 million was recorded to gas purchases offset by a corresponding decrease in the cost of a comparable amount of gas.

The actual amounts to be recorded in purchased energy expense are dependent on future changes in the contract values, the majority of these deferred amounts will be reclassified to expense within the next twelve months. A nominal amount of the hedging instruments extend into April 2006. There were no gains or losses recorded during the year from the discontinuance of gas futures or electricity swap cash flow hedges.

At March 31, 2005, Niagara Mohawk recorded a deferred gain on NYMEX electric swap contracts to hedge electricity purchases of $1.1 million. There were no open electric swaps at March 31, 2004.

NOTE F – SEGMENT INFORMATION

The Company's reportable segments are electricity-transmission, electricity-distribution, including the sub-segment stranded cost recoveries, gas-distribution and telecom. Certain information regarding the Company segments is set forth in the following table. Corporate assets consist primarily of other property and investments, cash, restricted cash, current deferred income taxes, and unamortized debt expense.

(in millions of dollars)

	Transmission	Distribution	Stranded Cost Recoveries	Total electricity distribution	Gas Distribution	Telecom	Corporate	Total
Year ended March 31, 2005								
Operating revenue	$ 444	$ 5,008	$ 785	$ 5,793	$ 808	$ 27	$ -	$ 7,072
Operating income before income taxes	226	568	226	794	105	6	-	1,131
Depreciation and amortization	78	262	-	262	37	6	-	383
Amortization of Stranded Costs	-	-	319	319	-	-	-	319
Year ended March 31, 2004								
Operating revenue	$ 451	$ 5,092	$ 849	$ 5,941	$ 780	$ 22	$ -	$ 7,194
Operating income before income taxes	210	366	223	589	68	5	-	872
Depreciation and amortization	76	260	-	260	36	4	-	376
Amortization of Stranded Costs	-	-	265	265	-	-	-	265
Year ended March 31, 2003								
Operating revenue	$ 611	$ 4,572	$ 895	$ 5,467	$ 709	$ 17	$ -	$ 6,804
Operating income before income taxes	192	497	232	729	68	4	-	993
Depreciation and amortization	75	263	-	263	36	4	-	378
Amortization of Stranded Costs	-	-	222	222	-	-	-	222
Goodwill								
At March 31, 2005	$ 641	$ 2,252	$ -	$ 2,252	$ 215	$ 129	$ -	$ 3,237
At March 31, 2004	$ 641	$ 2,253	$ -	$ 2,253	$ 215	$ 123	$ -	$ 3,232
Total Assets								
At March 31, 2005	$ 3,243	$ 10,187	$ 4,598	$ 14,785	$ 1,819	$ 253	$ 612	$ 20,712
At March 31, 2004	$ 3,056	$ 10,174	$ 4,781	$ 14,955	$ 1,686	$ 210	$ 538	$ 20,445

NOTE G - EMPLOYEE BENEFITS

Summary

The National Grid USA companies have non-contributory defined benefit pension plans covering substantially all employees. With the exception of New England-based union-represented employees, employees hired on or after July 15, 2002 participate in a cash balance pension plan design. Under that design, pay-based credits are applied based on service time, and interest credits are applied based on an average annual 30-year Treasury bond yield. Non-union employees hired by New England-based companies prior to July 15, 2002 and New England-based union employees generally participate in the historic final average pay pension plan designs that have been in effect for several decades. In addition, a large number of employees hired by Niagara Mohawk prior to July 1998 are cash balance design participants who receive a larger benefit if so yielded under pre-cash balance conversion final average pay formula provisions. Employees hired by Niagara Mohawk following the August 1998 cash balance design conversion participate under cash balance design provisions only.

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

The Company and its subsidiaries provide post retirement benefits other than pensions (PBOPs). PBOP future benefits include health care and life insurance coverage to eligible retired employees. Eligibility is based on certain age and length of service requirements and in some cases retirees must contribute to the cost of their coverage.

Funding Policy

In New England, absent unusual circumstances, the Company's funding policy is to contribute to the Plans each year the maximum tax deductible amounts for that year. In New York, the funding policy is determined largely by the Company's settlement agreements with the PSC and the amounts recovered in rates. However, the contribution for any year will not be less than the minimum contribution required by federal law or greater than the maximum tax-deductible amount.

Investment Strategy

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 reviewed based on the results of a periodic asset/liability study. This study includes an analysis of plan liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across the various fixed income market segments. For the PBOP obligations other than pension plan; 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 allocations. Investment risk and return is reviewed by the investment committee on a quarterly basis.

The target asset allocation for the pension benefit plans are:

	2005	2004
U.S. Equities	**44%**	42%
Global Equities (including U.S.)	**7%**	7%
Non-U.S. Equities	**11%**	11%
Fixed Income	**35%**	35%
Private Equity and Property	**3%**	5%
	100%	100%

The target asset allocation for the PBOP plans are:

	2005	2004
U.S. Equities	**50%**	50%
Non-U.S. Equities	**15%**	15%
Fixed Income	**35%**	35%
	100%	100%

Expected Rate of Return on Assets

The estimated rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of our long-term assumption. A small premium is added for active management of both equity and fixed income. The rates of return for each asset class are then weighted in accordance with the plans' target asset allocation, and the resulting long-term return on asset rate is then applied to the market-related value of assets.

The benefit plans' costs (for all subsidiaries) for the past three years included the following components and used the following assumptions.

(in thousands)	Qualified Pension Plans			Nonqualified Pension Plans			Other Retireme Benefits	
Net periodic benefit cost, for the year ended March 31,	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004
Service cost	**$ 50,656**	$ 47,342	$ 38,998	**$ 690**	$ 647	$ 563	**$ 22,200**	$ 17,930
Interest cost	**144,100**	146,273	154,127	**6,149**	6,578	7,133	**103,810**	98,849
Expected return on plan assets	**(165,347)**	(160,892)	(177,226)	**-**	-	-	**(73,880)**	(60,957)
Amortization of unrecognized prior service cost	**3,459**	2,809	1,681	**(149)**	(149)	(149)	**4,678**	(687)
Amortization of unrecognized loss	**53,385**	43,789	5,511	**1,016**	582	103	**36,756**	36,531
Net periodic benefit costs before settlements and curtailments	**86,253**	79,321	23,091	**7,706**	7,658	7,650	**93,564**	91,666
Settlement and curtailment loss	**-**	22,922	29,187	**185**	222	361	**-**	16,066
Special termination benefits	**-**	91,855	-	**-**	-	-	**-**	8,936
Net periodic benefit cost	**$ 86,253**	$ 194,098	$ 52,278	**$ 7,891**	$ 7,880	$ 8,011	**$ 93,564**	$ 116,668
Weighted average assumptions used to determine net periodic cost:								
Discount rate	**5.75%**	6.25%	7.50%	**5.75%**	6.25%	7.50%	**5.75%**	6.25%
Rate of compensation increase - New England	**4.70%**	4.63%	4.63%	**5.25%**	4.63%	5.25%	**N/A**	N/A
Rate of compensation increase - New York	**3.25%**	3.25%	3.25%	**5.25%**	5.25%	5.25%	**N/A**	N/A
Expected return on plan assets - Pension	**8.50%**	8.50%	8.75%	**N/A**	N/A	N/A	**N/A**	N/A
Expected return on plan assets - PBOP							**6.50%**	7.25%
Expected return on plan assets - PBOP							**9.00%**	8.75%
Medical trend								
Initial							**10.00%**	10.00%
Ultimate							**5.00%**	5.00%
Year that trend reaches ultimate rate							**2009**	2008

The following table provides a reconciliation of the changes in the Plans' fair value of assets for the fiscal years 2005 and 2004, the expected contributions to the trust in the following fiscal year, and the percentage distribution of the fair market value of the types of assets held in the benefit plans' trusts.

(in thousands)	Qualified Pension Plans		Nonqualified Pension Plans		PBOP	
	2005	2004	**2005**	2004	**2005**	2004
Change in plan assets:						
Beginning balance, April 1,	**$ 1,947,572**	$ 1,606,971	**$ -**	$ -	**$ 907,995**	$ 588,686
Actual return on plan assets	**134,990**	462,876	**-**	-	**49,373**	154,039
Employer contributions	**130,316**	155,090	**10,053**	9,788	**59,715**	205,945
Benefit payments	**(252,254)**	(144,292)	**(8,995)**	(8,399)	**(94,910)**	(40,675)
Settlements	**-**	(133,073)	**(1,058)**	(1,389)	**-**	-
Dispositions	**-**	-	**-**	-	**-**	-
Ending balance, March 31,	**$ 1,960,624**	$ 1,947,572	**$ -**	$ -	**$ 922,173**	$ 907,995
Distribution of plan assets, March 31,						
Debt securities	**34%**	34%	**N/A**	N/A	**39%**	36%
Equity securities	**65%**	64%	**N/A**	N/A	**59%**	62%
Property/real estate	**0%**	1%	**N/A**	N/A	**0%**	0%
Other	**1%**	1%	**N/A**	N/A	**2%**	2%
	100%	100%	**N/A**	N/A	**100%**	100%
Estimated contributions in following year	**$ 130,000**	$ 135,000	**$ 9,160**	$ 8,405	**$ 95,000**	$ 89,000

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

The following benefit payments and subsidies, which reflect expected future service, as appropriate, are expected to be paid from the Company's plans.

(in thousands)	Qualified Pension Plans		Nonqualified Pension Plans		PBOP	
	Payments	Subsidies	Payments	Subsidies	Payments	Subsidies
2006	$ 195,000	$ -	$ 9,000	$ -	$ 100,000	$ -
2007	190,000	-	9,000	-	105,000	8,000
2008	185,000	-	9,000	-	108,000	8,800
2009	184,000	-	9,000	-	110,000	9,400
2010	192,000	-	9,000	-	111,000	9,900
2011 - 2015	1,085,000	-	46,000	-	558,000	55,000

The following table provides a reconciliation of the changes in the Plans' fair benefit obligations for the fiscal years 2005 and 2004, accumulated benefit obligation for the pension plans at March 31, and the assumption used in developing the obligations.

(in thousands)	Qualified Pension Plans		Nonqualified Pension Plans		PBOP	
	2005	2004	**2005**	2004	**2005**	2004
Accumulated benefit obligation	**$ 2,409,544**	$ 2,373,523	**$ 111,044**	$ 110,807	**N/A**	N/A
Change in benefit obligation:						
Beginning balance, April 1,	**$ 2,609,731**	$ 2,441,307	**$ 114,190**	$ 113,805	**$ 1,834,258**	$ 1,585,462
Service cost	**50,656**	47,342	**690**	647	**22,200**	17,930
Interest cost	**144,100**	146,273	**6,149**	6,578	**103,810**	98,849
Actuarial losses	**112,221**	164,137	**1,762**	2,948	**9,435**	199,684
Plan amendments	**31,201**	-	**-**	-	**146,689**	(8,121)
Benefit payments	**(252,253)**	(144,292)	**(8,995)**	(8,399)	**(97,383)**	(85,203)
Settlements	**-**	(133,073)	**(1,057)**	(1,389)	**-**	-
Curtailments	**-**	(3,818)	**-**	-	**-**	16,721
Special termination benefits	**-**	91,855	**-**	-	**-**	8,936
Ending balance, March 31,	**$ 2,695,656**	$ 2,609,731	**$ 112,739**	$ 114,190	**$ 2,019,009**	$ 1,834,258
Weighted average assumptions as of March 31, to determine obligation						
Discount rate	**5.75%**	5.75%	**5.75%**	5.75%	**5.75%**	5.75%
Expected return on plan assets - Pension	**8.50%**	8.50%	**N/A**	N/A	**N/A**	N/A
Expected return on plan assets - PBOP Nonunion					**6.75%**	7.25%
Expected return on plan assets - PBOP Union					**8.50%**	8.75%
Medical trend						
Initial					**10.00%**	10.00%
Ultimate					**5.00%**	5.00%
Year ultimate is reached					**2010**	2009

The following table provides the funded status of the benefits and the amounts recognized on the balance sheets at March 31.

(in thousands)	Qualified Pension Plans		Nonqualified Pension Plans		PBOP	
	2005	2004	**2005**	2004	**2005**	2004
Reconciliation of (accrued)/prepaid cost, March 31,						
Funded status	**$ (735,032)**	$ (662,159)	**$ (112,739)**	$ (114,190)	**$(1,096,837)**	$ (926,263)
Unrecognized prior service cost	**54,888**	26,439	**(1,127)**	(1,276)	**133,106**	(8,906)
Unrecognized net loss	**831,986**	743,500	**22,596**	22,035	**597,757**	600,571
Net amount recognized at March 31,	**$ 151,842**	$ 107,780	**$ (91,270)**	$ (93,431)	**$ (365,974)**	$ (334,598)
Amounts recognized in the balance sheet consists of:						
Accrued benefit liability	**$ (432,628)**	$ (425,951)	**$ (111,044)**	$ (110,807)	**$ (365,974)**	$ (334,598)
Intangible asset	**54,888**	26,439	**-**	-	**-**	-
Regulatory asset	**252,218**	215,382	**-**	-	**-**	-
Accumulated other comprehensive income	**277,364**	291,910	**19,774**	17,376	**-**	-
Net amount recognized at March 31,	**$ 151,842**	$ 107,780	**$ (91,270)**	$ (93,431)	**$ (365,974)**	$ (334,598)

Change in Health Care Cost Trend Rate

Effect of one percentage point change in Health Care Cost Trend rate	PBOP	
	2005	2004
Increase 1%		
Total of service cost plus interest cost	**$ 21,637**	$ 14,603
Postretirement benefit obligation	**295,000**	193,880
Decrease 1%		
Total of service cost plus interest cost	**(18,196)**	(12,797)
Postretirement benefit obligation	**(257,030)**	(175,067)

PSC Audit

In connection with an audit performed by the New York State Public Service Commission (PSC) on one of the Company's subsidiaries, Niagara Mohawk reached a settlement with the PSC that resolves all issues associated with Niagara Mohawk's pension and other postretirement benefit obligations for the period prior to the acquisition of Niagara Mohawk by the Company. Among other things, the settlement covers the funding of Niagara Mohawk's pension and post-retirement benefit plans. Under the settlement, Niagara Mohawk agreed to provide $100 million of tax-deductible funding by April 30, 2003 (which it funded in March 2003), and an additional $209 million, on a tax-deductible basis, by December 31, 2011. Niagara Mohawk will earn a rate of return of at least 6.60 percent on any portion of the $209 million that it funds before December 31, 2011, plus 80 percent of the amount by which the rate of return on the pension and post-retirement benefit funds exceeds 5.34 percent. Niagara Mohawk has funded the additional $209 million to its pension and post-retirement benefit plans as of March 31, 2005.

Additional Minimum Pension Liability

The Company has recorded an additional minimum pension liability of approximately $621 million and $552 million at March 31, 2005 and 2004. While the offset to this entry would normally be a charge to other comprehensive income, the Company's subsidiaries NEP and Niagara Mohawk have recorded regulatory assets in the amount of $252 million and $237 million at March 31, 2005 and 2004, respectively, because they fully recover all pension costs.

Voluntary Early Retirement Offers

In fiscal 2004, National Grid USA companies made two voluntary early retirement offers (VEROs). The Company expensed approximately $67.2 million of non-union VERO costs in fiscal 2004.

Settlement Losses

As the result of the decline in the stock market since the close of the merger with Niagara Mohawk and a reduction in the discount rate applied to pension obligations, Niagara Mohawk has an unrecognized loss in its pension plans. Under Statement of Financial Accounting Standards No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" (FAS 88), Niagara Mohawk must recognize a portion of this loss immediately when payouts from the plans exceed a certain amount. Niagara Mohawk recognized settlement losses of $21.6 million and $29.5 million in fiscal year 2004 and 2003, respectively. In February 2004, Niagara Mohawk reached an agreement with PSC Staff that would provide rate recovery for approximately $15 million of the $30 million pension settlement loss incurred in fiscal 2003. This agreement was approved by the full New York State Public Service Commission in July 2004. In addition, the agreement covers the funding of the entire settlement loss to benefit plan trust funds. Under the agreement, Niagara Mohawk will fund the non-recoverable portion of this loss within 30 days of receipt of the written order, which is expected to become effective in August 2004. Niagara Mohawk recorded this recovery in the second quarter of fiscal 2005. In addition, Niagara Mohawk has recently filed a petition with the PSC seeking recovery of its fiscal year 2004 settlement losses and is unable to predict the outcome of this filing.

Regulatory treatment of pensions and PBOP

In addition to the regulatory assets established in connection with purchase accounting and the additional minimum pension liability discussed above, the regulatory asset account "Pension and postretirement benefit plans" includes certain other components. First, Niagara Mohawk is required under the Merger Rate Plan to defer the difference between pension and postretirement benefit expense and the allowance in rates for these costs. Also, the regulatory asset account includes the $52 million cost of Niagara Mohawk's Voluntary Early Retirement Program (VERP) that occurred in conjunction with its acquisition by the Company, and a postretirement benefit phase-in deferral established in the mid-1990's. The VERP is being amortized unevenly over the 10 years of Niagara Mohawk's Merger Rate Plan with larger amounts being amortized in the earlier years. VERP amortization in fiscal 2005 and 2004 was approximately $7 million and $8 million, respectively. The phase-in deferral is being amortized at a rate of approximately $3 million per year.

Defined contribution plan

The Company also has a defined contribution pension plan (a section 401(k) employee savings fund plan) that covers substantially all employees. Employer matching contributions of $10 million and $12 million were expensed in fiscal 2005 and 2004, respectively.

Medicare Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act was signed into law on December 8, 2003. It created a new Medicare prescription drug benefit (Medicare Part D) and a federal subsidy to sponsors of retiree healthcare plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. On May 19, 2004, the FASB issued Staff Position No. 106-2m "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the FSP). The FSP provides guidance on accounting for the effects of the Act, which resulted in a reduction in the APBO for the subsidy related to benefits attributed to past service. The reduction in the APBO represents a deferred actuarial gain in the amount of $153.4 million for the plans as of July 1, 2004. On January 21, 2005, final regulations were issued on the new Medicare prescription drug program. The impact on plan obligations as a result of the final regulations was not significant.

(In thousands)		2005
Service cost	$	**1,220**
Interest cost		**7,396**
Recognized actuarial loss		**8,904**
Net periodic benefit cost	$	**17,520**
Annualized expense reduction	$	**23,360**

NOTE H – INCOME TAXES

The Company and its subsidiaries participate with National Grid General Partnership (NGGP), a wholly owned subsidiary of NGT, in filing consolidated federal income tax returns. The Company's income tax provision is calculated on a separate return basis. Federal income tax returns have been examined and all appeals and issues have been agreed upon by the Internal Revenue Service and the Company through 1998.

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

	For the Year Ended March 31,					
(In thousands)		**2005**		2004		2003
Income taxes charged to operations	$	**306,229**	$	269,667	$	228,729
Income taxes charged (credited) to "Other income"		**(4,263)**		1,534		1,450
Total income taxes	$	**301,966**	$	271,201	$	230,179

Total income taxes, as shown above, consist of the following components:

(In thousands)	For the Year Ended March 31, 2005	2004	2003
Current income taxes	$ **88,011**	$ 127,597	$ 108,700
Deferred income taxes	**220,121**	150,422	128,507
Investment tax credits, net	**(6,166)**	(6,818)	(7,028)
Total income taxes	$ **301,966**	$ 271,201	$ 230,179

Total income taxes, as shown above, consist of federal and state components as follows:

(In thousands)	For the Year Ended March 31, 2005	2004	2003
Federal income taxes	$ **273,269**	$ 235,775	$ 196,496
State income taxes	**28,697**	35,426	33,683
Total income taxes	$ **301,966**	$ 271,201	$ 230,179

Since 1998, NEP has been amortizing previously deferred ITC related to generation investments over the CTC recovery period. Unamortized ITC related to generating units divested in 1998 and 2001 were credited to other income pursuant to federal tax law.

Previously recognized ITC related to the transmission and distribution facilities of National Grid USA's regulated subsidiaries are amortized over their estimated productive lives.

With regulatory approval, the subsidiaries have adopted comprehensive interperiod tax allocation (normalization) for temporary book/tax differences.

Total income taxes differ from the amounts computed by applying the federal statutory tax rates to income before taxes. The reasons for the differences are as follows:

(In thousands)	For the Year ended March 31, 2005	2004	2003
Computed tax at statutory rate	$ **299,483**	$ 185,853	$ 187,058
Increases (reductions) in tax resulting from:			
Amortization of ITC, net	**(6,013)**	(6,616)	(6,864)
State income tax, net of federal income tax benefit	**28,894**	23,027	21,896
Tax return true-ups	**(26,308)**	20,232	12,476
Foreign tax credits unutilized	**-**	32,350	-
Rate recovery of deficiency in deferred tax reserves	**1,856**	2,455	1,851
Book/tax depreciation normalized	**16,852**	21,328	16,093
Unamortized debt discount not normalized	**487**	(1,556)	3,196
Cost of removal	**(5,664)**	(6,857)	(6,630)
Medicare act	**(5,907)**	-	-
All other differences	**(1,714)**	985	1,103
Total income taxes	$ **301,966**	$ 271,201	$ 230,179

The Company applies SFAS No. 109, "Accounting for Income Taxes", which requires recognition of deferred income taxes for temporary differences that are reported in different years for financial reporting and tax purposes using the liability method. Under the liability method, deferred tax liabilities or assets are computed using the tax rates that will be in effect when temporary differences reverse. Generally, for regulated companies, the change in tax rates may not be immediately recognized in operating results because of rate-making treatment and provisions in the Tax Reform Act of 1986.

The following is a detail of the Company's accumulated deferred income taxes:

(In thousands)	At March 31, 2005	At March 31, 2004
Deferred tax assets:		
Plant related	**$ 110,725**	$ 104,576
Alternative Minimum Tax	**111,609**	81,639
Unbilled revenues	**54,030**	22,611
Non-utilized NOL carryforward	**105,023**	307,743
Liability for environmental costs	**229,723**	148,325
Voluntary early retirement program	**41,558**	219,237
Bad debts	**62,046**	29,474
Pension and other post-retirement benefits	**185,324**	40,830
Investment tax credit	**12,146**	14,080
Other	**276,520**	464,789
Total deferred tax assets	**1,188,704**	1,433,304
Deferred tax liabilities:		
Plant related	**(1,358,129)**	(1,342,168)
Equity AFUDC	**(62,468)**	(62,127)
Deferred environmental restoration costs	**(200,175)**	(148,325)
Merger rate plan stranded costs	**(848,182)**	(896,816)
Merger fair value pension and OPEB adjustment	**(128,188)**	(146,898)
Bond redemption and debt discount	**(29,233)**	(30,772)
Pension and other post-retirement benefits	**(141,422)**	(110,163)
Other	**(284,903)**	(400,870)
Total deferred tax liabilities	**(3,052,700)**	(3,138,139)
Net accumulated deferred income tax liability	**(1,863,996)**	(1,704,835)
Current portion (net deferred tax asset)	**340,837**	248,642
Net accumulated deferred income tax liability (noncurrent)	**$ (2,204,833)**	$ (1,953,477)

In December 1998, Niagara Mohawk received a ruling from the IRS which provided that the amount of cash and the value of common stock that was paid by Niagara Mohawk to the subject terminated IPP Parties was deductible in 1998 which resulted in Niagara Mohawk not paying any regular federal income taxes for 1998, and further generated a substantial net operating loss for federal income tax purposes. Niagara Mohawk carried back a portion of the unused net operating loss (NOL) to the years 1996 and 1997, and also for the years 1988 through 1990, which resulted in federal income tax refunds of $135 million that were received in January 1999. As a result of the merger with the Company, Niagara Mohawk is now part of the consolidated tax return filing group of NGGP. The Company anticipates that the consolidated tax filing group will be able to utilize the remaining NOL carryforward prior to its expiration in 2019. The amount of the NOL carryforward as of March 31, 2005 and 2004 was $301 million and $909 million, respectively. The Company's ability to utilize the NOL carryforward generated as a result of the Merger Rate Agreement and the utilization of alternative minimum tax credits is affected by the rules of Section 382 of the Internal Revenue Code. There were no valuation allowances for deferred tax assets deemed necessary at March 31, 2005 or 2004.

NOTE I – LONG-TERM DEBT

Long-term debt consists of the following:

Narragansett Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
First Mortgage Bonds:				
V(94-4)	7.420	June 15, 2004	$ -	$ 5,000
V(94-6)	8.330	November 8, 2004	-	10,000
U(93-3)	6.650	June 30, 2008	**5,000**	5,000
V(94-1)	8.080	May 2, 2024	-	5,000
V(94-5)	8.160	August 9, 2024	-	5,000
V(95-2)	7.750	June 2, 2025	**10,000**	10,000
V(95-3)	7.500	October 10, 2025	**7,000**	7,000
W(95-1)	7.300	November 13, 2025	**16,000**	16,000
W(96-1)	7.240	January 19, 2026	**2,000**	2,000
W(97-1)	7.390	September 30, 2027	**3,000**	3,000
W(97-2)	7.390	October 1, 2027	**7,000**	7,000
Subtotal - Narragansett Electric			**$ 50,000**	$ 75,000

Massachusetts Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
First Mortgage Bonds:				
U(94-6)	8.520	November 30, 2004	$ -	$ 10,000
U(95-1)	8.450	January 10, 2005	-	10,000
U(95-2)	8.220	January 24, 2005	-	10,000
U(95-7)	7.920	March 3, 2005	-	9,000
V(95-1)	6.720	June 23, 2005	**10,000**	10,000
V(96-1)	6.780	November 20, 2006	**20,000**	20,000
T(93-7)	6.660	June 23, 2008	**5,000**	5,000
T(93-8)	6.660	June 30, 2008	**5,000**	5,000
T(93-10)	6.110	September 8, 2008	**10,000**	10,000
T(93-11)	6.375	November 17, 2008	**10,000**	10,000
V(98-3)	5.720	November 24, 2008	**25,000**	25,000
U(94-2)	8.080	May 2, 2024	-	5,000
U(94-3)	8.030	June 14, 2024	-	5,000
U(94-4)	8.160	August 9, 2024	-	5,000
U(94-5)	8.850	November 7, 2024	-	1,000
U(95-6)	8.460	February 28, 2025	-	3,000
V(95-2)	7.630	June 27, 2025	**10,000**	10,000
V(95-3)	7.600	September 12, 2025	**10,000**	10,000
V(95-4)	7.630	September 12, 2025	**10,000**	10,000
V(97-1)	7.390	October 1, 2027	**15,000**	15,000
V(98-1)	6.910	January 12, 2028	**20,000**	20,000
V(98-2)	6.940	January 12, 2028	**5,000**	5,000
Pollution Control Revenue Bonds:				
1993	5.875	August 1, 2008	**40,000**	40,000
Subtotal - Massachusetts Electric			**$ 195,000**	$ 253,000

Granite State Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
Note	7.370	November 1, 2023	**$ 5,000**	$ 5,000
Note	7.940	July 1, 2025	**5,000**	5,000
Note	7.300	June 15, 2028	**5,000**	5,000
Subtotal - Granite State Electric			**$ 15,000**	$ 15,000

Niagara Mohawk
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
First Mortgage Bonds:				
8%	8.000	June 1, 2004	$ -	$ 232,425
6 5/8%	6.625	July 1, 2005	**110,000**	110,000
9 3/4%	9.750	November 1, 2005	**137,981**	137,981
7 3/4%	7.750	May 15, 2006	**275,000**	275,000
6 5/8% (1)	6.625	October 1, 2013	**45,600**	45,600
5.15%	5.150	November 1, 2025	**75,000**	75,000
7.2% (2)	7.200	July 1, 2029	**115,705**	115,705
Senior Notes:				
5 3/8%	5.375	October 1, 2004	-	300,000
7 5/8%	7.625	October 1, 2005	**302,439**	302,439
8 7/8%	8.875	May 15, 2007	**200,000**	200,000
7 3/4%	7.750	October 1, 2008	**600,000**	600,000
Promissory Notes: (3)				
2015	Variable	July 1, 2015	**100,000**	100,000
2023	Variable	December 1, 2023	**69,800**	69,800
2025	Variable	December 1, 2025	**75,000**	75,000
2026	Variable	December 1, 2026	**50,000**	50,000
2027	Variable	March 1, 2027	**25,760**	25,760
2027	Variable	July 1, 2027	**93,200**	93,200
Notes Payable:				
NM Holdings Note	3.720	July 31, 2009	**350,000**	350,000
NM Holdings Note	3.830	June 30, 2010	**350,000**	350,000
NM Holdings Note	5.800	November 1, 2012	**500,000**	500,000
Other			-	195
Subtotal - Niagara Mohawk			**$ 3,475,485**	$ 4,008,105

(1) Refinanced to auction rate mode on December 11, 2003. Effective interest rate at March 31, 2005 and March 31, 2004 was 2.70 percent and 1.18 percent, respectively.

(2) Refinanced to auction rate mode on May 27, 2004. Effective interest rate at March 31, 2005 was 2.10 percent.

(3) Refinanced to auction rate mode on May 1, 2003. Effective interest rate at March 31, 2005 and March 31, 2004 was 2.35 percent and 1.19 percent, respectively.

Hydros
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
Series B	9.260	April 17, 2007	**$ 12,110**	$ 21,380
Series C	9.410	October 17, 2015	**46,270**	46,270
Subtotal - Hydros			**$ 58,380**	$ 67,650

Nantucket Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
2004 Series 1996 MIFA Tax Exempt	5.300	July 1, 2004	$ -	$ 1,400
2005 Series 1996 MIFA Tax Exempt	6.750	July 1, 2005	**1,400**	1,400
2006 Series 1996 MIFA Tax Exempt	6.750	July 1, 2006	**1,400**	1,400
2007 Series 1996 MIFA Tax Exempt	5.600	July 1, 2007	**1,400**	1,400
2008 Series 1996 MIFA Tax Exempt	5.750	July 1, 2008	**1,400**	1,400
2009 Series 1996 MIFA Tax Exempt	5.750	July 1, 2009	**1,400**	1,400
1991 $3.5 Million MIFA Tax-Exempt	Variable	March 1, 2016	**2,640**	2,775
2017 Series 1996 MIFA Tax Exempt	5.875	July 1, 2017	**20,500**	10,500
Subtotal - Nantucket Electric			**$ 30,140**	$ 21,675

New England Power
At March 31 (In thousands)

Series	Rate %	Maturity	2005	2004
Pollution Control Revenue Bonds: (1)				
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
Subtotal - New England Power			**$ 410,350**	$ 410,350

(1) At March 31, 2005, interest rates on NEP's variable rate bonds ranged from 1.90 percent to 2.18 percent.

Totals - National Grid USA

At March 31 (In thousands)	2005	2004
Total long-term debt	**$ 4,234,355**	$ 4,850,780
Unamortized Discount on Debt	**(2,572)**	(3,235)
Long-term debt due within one year	**567,725**	597,230
Total long-term debt, excluding current portion	**$ 3,664,058**	$ 4,250,315

Substantially all of the properties of the Company are subject to liens of mortgage indentures under which mortgage bonds have been issued.

As of March 31, 2005, the aggregate payments to retire maturing long term debt are as follows (in thousands):

Fiscal Year	Amount
2006	$ 561,820
2007	296,400
2008	213,510
2009	701,400
2010	351,400
Thereafter	2,109,825
	$ 4,234,355

At March 31, 2005, the Company's subsidiaries' long term debt excluding intercompany debt had a carrying value of $3.0 billion and a fair value of $3.1 billion. The fair value of debt that re-prices frequently at market rates approximates carrying value. The fair market value of the Company's subsidiaries' long term debt was estimated based on the quoted prices for similar issues or on the current rates offered to the Company and its subsidiaries for debt of the same remaining maturity.

NOTE J – SHORT-TERM DEBT

NEP

At March 31, 2005 and 2004, NEP had lines of credit and standby bond purchase facilities with banks totaling $440 million and $439 million, respectively, which is available to provide liquidity support for $410 million of NEP's long-term bonds in tax-exempt commercial paper mode, and for other corporate purposes. The agreement with banks that provide NEP's line of credit and standby bond purchase facility expires on November 29, 2009, subject to regulatory approval. NEP plans to seek such regulatory approval later this year. There were no borrowings under these lines of credit at March 31, 2005. Fees are paid on the lines and facilities in lieu of compensating balances.

Inter-company money pool

The Company and certain subsidiaries operate a money pool 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 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 $2 billion from its parent (through intermediary entities), National Grid Transco (NGT), and certain other subsidiaries of NGT, including for purpose of funding the money pool if necessary. At March 31, 2005 and 2004, the Company had borrowed $619 and $383 million respectively, under this arrangement.

NOTE K – CUMULATIVE PREFERRED STOCK

A summary of cumulative preferred stock at March 31, 2005 and 2004 is as follows (in thousands except for share data and call price):

	Company	Shares Outstanding		Amount (in 000's)		Call Price
		March 31, 2005	March 31, 2004	**March 31, 2005**	March 31, 2004	
$100 par value -						
3.40% Series	Niagara Mohawk	**57,536**	57,536	**$ 5,754**	$ 5,754	$ 103.500
3.60% Series	Niagara Mohawk	**137,139**	137,139	**13,714**	13,714	104.850
3.90% Series	Niagara Mohawk	**94,967**	94,967	**9,496**	9,497	106.000
4.10% Series	Niagara Mohawk	**52,830**	52,830	**5,283**	5,283	102.000
4.44% Series	Mass Electric	**22,585**	22,585	**2,259**	2,259	104.068
4.76% Series	Mass Electric	**24,680**	24,680	**2,468**	2,468	103.730
4.85% Series	Niagara Mohawk	**35,128**	35,128	**3,513**	3,513	102.000
5.25% Series	Niagara Mohawk	**34,115**	34,115	**3,410**	3,411	102.000
6.00% Series	New England Power	**11,117**	12,734	**1,112**	1,273	(a)
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**2,454**	2,453	55.000
4.64% Series	Narragansett	**57,057**	57,057	**2,854**	2,853	52.125
$25 par value -						
Adjustable Rate Series D	Niagara Mohawk	**-**	503,100	**-**	25,155	(b)
Total		**576,243**	1,080,960	**$ 52,317**	$ 77,633	

(a) Noncallable.
(b) Callable on or after December 31, 2004 at $50.

NOTE L – COST OF REMOVAL

In 2001, FASB issued SFAS No. 143, “Accounting for Asset Retirement Obligations” (FAS 143). FAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company was required to adopt FAS 143 as of April 1, 2003. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

Management does not believe the Company has any material asset retirement obligations arising from legal obligations as defined under FAS 143. 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 FAS 143’s 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. For a vast majority of its electric and gas transmission and distribution assets the Company would use these funds to remove the asset so a new one could be installed in its place.

The collection of cost of removal collected from customers has historically been embedded within accumulated deprecation (as these costs have been charged over time through deprecation expense). With the adoption of FAS 143 the Company has reclassed the cost of removal collections to a regulatory liability account to more properly reflect the future usage of these collections. The Company estimates it has collected over time approximately $505 million and $487 million for cost of removal through March 31, 2005 and March 31, 2004, respectively.

In March 2005, the FASB issued FIN 47 that clarifies that the term ‘conditional asset retirement obligation’ used in SFAS No. 143, ‘Accounting for Asset Retirement Obligation’ (SFAS 143) 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 even that may or may not be within the control of the Group. This statement will be effective for the fiscal year ended March 31, 2006 for the Company. The adoption of FIN 47 is not expected to have a material impact on the Company’s results of operations or its financial position.