National Grid USA / Annual Report

Fiscal year ended March 31, 2006

Cautionary Statement

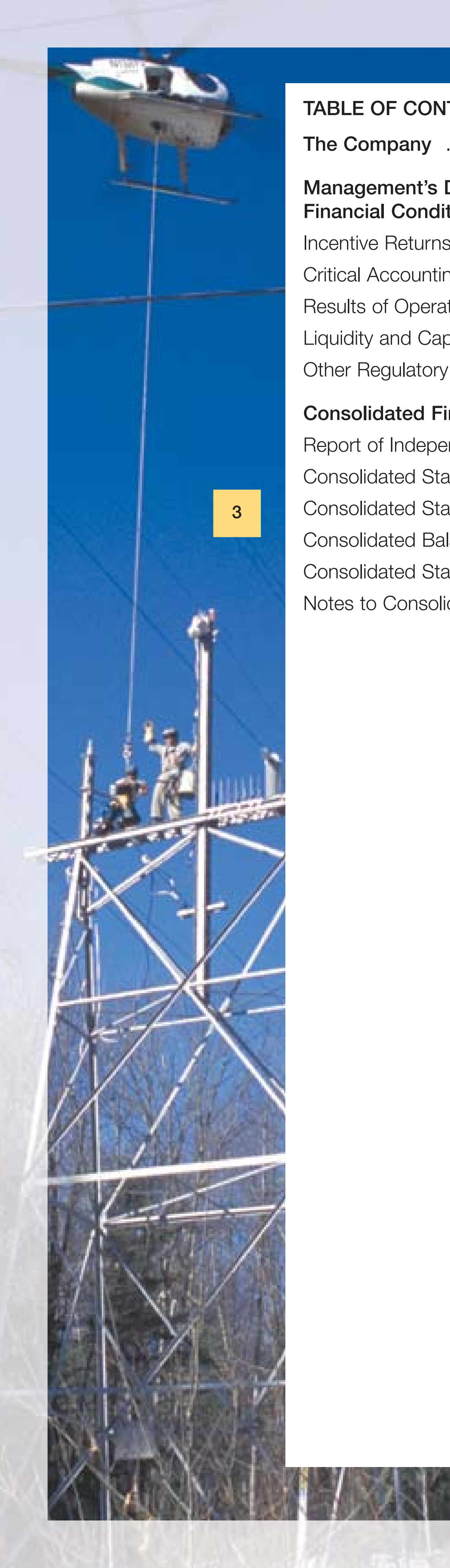
This Annual Report of National Grid USA contains certain statements that are neither reported financial results nor other historical information. These statements are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities 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; labor costs; interest rates; changes in tax laws; political environment; adverse changes in electric load; 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 (SFAS) 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 plc's Annual Report and Accounts 2005/06, available at www.nationalgrid.com, or as part of National Grid plc's Annual Report on Form 20-F for fiscal year ended March 31, 2006 and other reports filed with the US Securities and Exchange Commission (the SEC). The Company's subsidiary, Niagara Mohawk Power Corporation also files reports with the SEC. 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 activities of the principal operating companies are summarized in the table below.

Company and service area	**Calendar 2006 Customer Base** (approximately)	**Fiscal 2006 Financial information** (before intercompany eliminations) ($'s in 000's)	
Niagara Mohawk Power Corporation Electricity and gas distribution and electricity transmission company serving eastern, central, northern and western New York	1.6 million electric customers in 669 cities and towns 569,000 gas customers in 197 cities and towns	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 4,344,023 549,676 317,076 12,280,968
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:	$ 2,317,645 116,580 91,804 3,449,889
The Narragansett Electric Company Electricity distribution company serving the state of Rhode Island	479,000 customers in 38 cities and towns	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 954,493 60,325 50,544 1,725,544
Granite State Electric Company Electricity distribution company serving Southern New Hampshire and portions of the Connecticut River Valley	41,000 customers in 21 communities	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 80,636 8,605 7,384 115,612

Company and service area	Calendar 2006 Customer Base (approximately)	Fiscal 2006 Financial information (before intercompany eliminations) ($'s in 000's)	
Nantucket Electric Company Electricity distribution company serving Nantucket Island	12,000 customers on Nantucket Island	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 21,820 2,778 993 110,659
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:	$ 675,931 84,925 76,363 2,457,579
National Grid Wireless Holdings, Inc. Telecommunications infrastructure companies providing services in the northeastern United States region from New England to Virginia.	Comprised of the following entities: National Grid Wireless Holdings, Inc., NEES Communications, Inc., National Grid Communications, Inc., and National Grid Wireless Services, Inc.	Operating Revenue: Operating Profit: Net Income: Total Assets:	$ 51,145 4,479 4,124 267,905

Announced acquisitions

In February 2006, the Company entered into two agreements to significantly expand operations in the northeastern United States. These two agreements comprise the proposed acquisition of KeySpan Corporation (KeySpan) for $7.3 billion together with the assumption of approximately $4.5 billion of debt and the acquisition from Southern Union Company of its Rhode Island gas distribution network for cash consideration of $498 million and assumed debt of $77 million. Both businesses have a history of performing under incentive-based rate plans, which provide substantial benefits to customers and shareholders.

KeySpan is the fifth largest distributor of natural gas in the United States and the largest in the northeastern United States, serving 2.6 million customers in New York, Massachusetts and New Hampshire. KeySpan also operates an electricity transmission and distribution network serving 1.1 million customers in New York under a long-term contract with the Long Island Power Authority. KeySpan's other interests include 6.7 GW of generation capacity, together with a small portfolio of non-regulated energy-related services and strategic investments in certain gas pipeline, storage and liquefied natural gas assets.

The proposed acquisition of KeySpan is subject to approvals from federal and state regulatory authorities, the Company's shareholders and KeySpan's shareholders, and is planned to be completed in 2007. Of these approvals, National Grid has cleared regulatory reviews by the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act and by the Committee on Foreign Investment in the United States under the Defense Production Act. The proposed acquisition was approved by National Grid's shareholders on July 31, 2006 and by Keyspan's shareholders on August 17, 2006.

Southern Union Company's Rhode Island gas distribution business serves approximately 245,000 customers through a distribution network of over 3,000 miles of mains. The network substantially overlaps the Company's existing electricity distribution service area in Rhode Island. The rates for the Rhode Island gas distribution business are set by the same state regulators that set the Company's electricity distribution rates in Rhode Island.

The acquisition of the Rhode Island gas distribution network closed on August 24, 2006.

GridAmerica

Effective November 1, 2005, Ameren withdrew from GridAmerica. 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 England – USGen New England Inc. (USGen) Settlement

Wholesale supplier bankruptcy settlement

When New England Power Company (NEP) divested its generating business in 1998, it transferred its entitlement to power procured under several long-term contracts (the Contracts). The buyers of NEP's generating business (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 monthly amount for the above-market cost of the Contracts. NEP resumed the performance and payment obligations under power supply contracts that had been transferred to USGen and removed the related liability from the balance sheet and offsetting regulatory asset for the above market portion of the contracts with USGen. NEP continues to record a derivative liability of approximately $294 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 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 $196 million in June 2005 from USGen. That amount relates in part to the Contracts and NEP is crediting that amount to customers through a reduction in rates through December 31, 2009.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INCENTIVE RETURNS UNDER RATE PLANS

Under rates approved by the applicable regulators in New York, Massachusetts, New Hampshire and Rhode Island, the Company recovers its (i) costs of providing electricity and gas distribution services, (ii) costs of providing transmission services and (iii) stranded costs. The rates are set based on historical or forecasted costs, and the Company earns a return on its assets, including a return on the "stranded costs" associated with the divestiture of the Company's generating assets under deregulation. 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. Commodity costs are passed through directly to customers. The Company is also subject to service quality standards in New York, Massachusetts and Rhode Island with respect to reliability and other aspects of customer service. The Company is subject to penalties if it fails to meet certain targets and, in Massachusetts, the Company can earn incentives for outstanding performance.

Niagara Mohawk Power Corporation

Niagara Mohawk Power Corporation's (Niagara Mohawk) electricity delivery rates are governed by a ten-year rate plan that began on February 1, 2002. Under the plan, after reflecting Niagara Mohawk's share of savings related to the acquisition, Niagara Mohawk may earn a threshold return on equity (ROE) of 10.6%, up to 11.75% without any sharing with customers (12.0% if certain customer outreach, education, competition related and low income incentive targets are met). Half of any amounts in excess of 12%, up to 14%, 25% of any earnings in excess of that up to 16% and 10% beyond that are retained by the Company. This effectively offers Niagara Mohawk the potential to achieve a ROE in excess of the regulatory allowed return of 10.6%. The ROE is calculated cumulatively from inception to December 31, 2005 and annually thereafter for the prior two calendar years. 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. 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. Niagara Mohawk may earn a threshold ROE ranging from 10.6% to 12.6% depending on the achievement of certain customer migration levels and customer awareness and understanding of gas competitive opportunities. Above this threshold, the revenue equivalent of gas earnings must be shared equally between shareholders and customers.

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.

Massachusetts Electric Company

Under Massachusetts Electric Company's (Massachusetts Electric) long-term rate plan, which runs until May 2020, there is no cap on earnings and no earnings sharing reflected in distribution rates until 2010. From May 2000 until February 2005, rates were frozen. In March 2005, a settlement credit in Massachusetts Electric's rates expired, which represents an increase of $11 million in pre-tax income through February 2006. Beginning in March 2006, rates are adjusted each March until 2009 by the annual percentage change in average electricity distribution rates in the northeastern United States. Regulators approved the first such annual increase in the amount of $20 million, effective March 1, 2006. In 2009, actual earned savings will be determined and Massachusetts Electric 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 before tax. Earned savings represent the difference between a test year's distribution revenue and Massachusetts Electric's cost of providing service during the same test year, 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.

Narragansett Electric Company

In Rhode Island, Narragansett Electric Company's (Narragansett) distribution rates are governed by a long-term rate plan. Between May 2000 and the end of October 2004, distribution rates were frozen and Narragansett was permitted to retain 100% of its earnings up to an allowed ROE of 12%. Narragansett kept 50% of earnings between 12% and 13%, and 25% of earnings in excess of 13%. Under a new long-term rate plan, effective from November 2004 until December 2009, Narragansett Electric agreed to reduce its distribution rates by $10.2 million (pre-tax) per year. Beginning in January 2005, Narragansett has been able to keep an amount equal to 100% of its earnings up to an allowed ROE of 10.5%, plus $4.7 million (pre-tax), which represents its share of demonstrated savings subsequent to the acquisition of Eastern Utilities Associates in 2000. 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. This regulatory mechanism offers the potential to achieve returns in excess of traditional regulatory allowed returns.

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 ROE of 12.8%, subject to refund, plus an additional 0.5% incentive return on regional network service (RNS) rates that FERC approved in March 2004. Approximately 70% of NEP'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. In June and July 2005, parties to the proceeding filed two rounds of briefs in response to the initial decision and opposing one another's positions. New England transmission owners continue to request a base ROE of 11.8% for all facilities before adding the .5% RTO participation adder and the 1% adder applicable to new transmission investment. Other parties are proposing a base ROE ranging from 9.14% to 10.64%, with some parties proposing to allow the 1% adder only for a small subset of projects and others proposing that the 1% adder is not justified under any circumstances.

The parties continue to await a final decision by the FERC.

On June 30, 2006, the US Court of Appeals affirmed FERC's 2004 order awarding the 0.5% RTO participation adder on RNS rates. The Court also ruled that FERC acted lawfully when it denied the 0.5 % incentive adder on transmission owners' ROE for local network service (LNS) rates. In addition, the Court affirmed FERC's requiring that any transmission owner that might seek to withdraw from the RTO must first satisfy the Commission that the withdrawal would be just and reasonable.

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 cash flows of the Company under generally accepted accounting principles in the United States. 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, tax 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 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," which requires regulated entities, in appropriate circumstances, to establish regulatory assets or liabilities, and thereby defer the income statement impact of certain charges or revenues because they are expected to be collected or refunded through future customer billings. 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 SFAS No. 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. Substantially all of the Company's business, including the recovery of its stranded costs, remains under cost based 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," and SFAS No. 149, "Amendment of SFAS No. 133 on Derivative Instruments and Hedging Activities," as amended. Under the provisions of SFAS No.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 125% of the changes in fair value or cash flows of the hedged item. The Company also has power purchase agreements with non-affiliates for the purchase of power and capacity for resale to its retail customers. These agreements generally have no notional amounts and do not meet the definition of a derivative under SFAS No. 133.

Revenue Recognition

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 Company recognizes changes in unbilled electric revenues in its results of operations. Pursuant to Niagara Mohawk's 2000 multi-year gas settlement (which ended December 2004, with Niagara Mohawk having the right to request a change in rates at any time, if needed), changes in accrued unbilled gas revenues are deferred.

Goodwill

The Company applies the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets." In accordance with SFAS No. 142, goodwill must be reviewed for impairment at least annually and when events or circumstances indicate 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. The result of the annual analysis determined that no adjustment to the goodwill carrying value was required. During fiscal year 2006, the Company made an adjustment to goodwill of approximately $32 million. This amount primarily related to (i) an adjustment to Niagara Mohawk goodwill of $9 million due to the settlement of an Internal Revenue Service audit of pre-merger years related to a pre-merger tax contingency and (ii) an adjustment to Massachusetts Electric, Narragansett, and NEP goodwill of $15 million, $7 million and $1 million respectively, which related to the reclassification of long-term balance sheet accounts.

Tax Provision

The Company's income 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". Determination of current year federal and state income tax will not be settled until final approval of returns by the taxing authorities.

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 and Other Post-retirement Benefit Plans

The Company maintains qualified and nonqualified pension plans. The Company also provides health care and life insurance benefits for its retired employees known as post-retirement benefits. The Company's qualified pensions are funded through a third party trust.

Additional minimum pension liability (AML) is recognized under SFAS No. 87, "Employers' Accounting for Pensions." Consistent with current rate agreements, Niagara Mohawk and NEP recovers all costs associated with its qualified pension plan due to the nature of its rate plan and has recorded a regulatory asset as an off-set to the qualified plan AML. The AML for the Niagara Mohawk non-qualified plan is off-set through an adjustment to accumulated other comprehensive income (net of tax).

The additional minimum pension liability for the Company's other subsidiaries is recognized in the balance sheet as a liability with an offsetting charge to other comprehensive income (net of tax).

Several assumptions affect the pension and other post-retirement benefit expense and the measurement of these benefit obligations. The more significant assumptions are as follows:

- *Return on assets*. The assumed rate of return for various passive asset classes is based on both analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of long-term assumptions. A small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the target asset allocation, and the resulting long-term return on asset rate is then applied to the market-related value of assets. For fiscal 2006, the Company used an 8.25% assumed return on assets for its pension plan and an 8.05% assumed return on assets for its other post-retirement benefits plans.
- *Discount rate.* The Company bases its discount rate on two measures of rates specific to the yield curve applicable to the liabilities of the plans. The actuary calculates the present value of the projected cash flows of the plans utilizing derived zero coupon interest rates specific to the timing of each respective cash flow and calculates the single weighted average interest rate that equates the total present value with the stream of future cash flows. This results in a weighted average interest rate of 5.87% based on the Citigroup Pension Discount Curve, which is based on AA-rated corporate bonds, and an interest rate of 6.16% based on a yield curve of top quartile yielding Aa corporate bonds. A discount rate of 6%, the average between the two rates, was deemed appropriate for the plans for fiscal year 2006.
- *Medical cost trends*. The health care cost trend rate is the assumed rate of increase in per-capita health care charges. In fiscal year 2006, the health care cost trend assumption was updated to include rates for the pre-65 and post-65 age groups. For fiscal year 2006, the initial health trend was assumed to be 10% for the pre-65 age group and 11% for the post-65 age group. The ultimate trend of 5%, for both age groups, was assumed to be reached in 2011 for the pre-65 age group and 2012 for the post-65 age group.

FASB Exposure Draft on Pension and Other Post-retirement Benefits

On March 31, 2006, the FASB issued an Exposure Draft of proposed rules on employers' accounting for defined benefit pensions and other postretirement benefit plans that would require employers to fully recognize the plan's funded status on the balance sheet. If adopted as proposed, the new rules would be effective for fiscal years ending after December 15, 2006. The new rules, if adopted as proposed, may significantly increase the Company's recorded pension and other post-retirement liabilities and reduce its shareholders' equity. NEP and Niagara Mohawk, as set forth in each of their respective current rate agreements, would recover the additional pension costs from customers and therefore the costs would be recognized as a regulatory asset upon adoption. The comment period on this Exposure Draft ended on May 31, 2006. The Company is currently evaluating the Exposure Draft, and at this time cannot determine the full impact that the potential requirements of the Exposure Draft may have on its financial statements.

RESULTS OF OPERATIONS

The following discussion and analysis highlights items that significantly affected the Company's operations during the fiscal years ended March 31, 2006 and 2005.

EARNINGS

Net income for the fiscal year ended March 31, 2006 increased approximately $8 million (2%) as compared to the prior fiscal year and increased approximately $288 million (108%) for the fiscal year ended March 31, 2005 as compared to the prior fiscal year. The increases are primarily due to the following:

		Fiscal year ended March 31,	
	Notes	**2006**	2005
Prior year net income		**$ 553,698**	$ 266,084
Changes in:			
Electric margin		**112,783**	1,953
Gas margin		**(1,623)**	1,406
Other operation and maintenance	(a)	**(87,757)**	248,996
Depreciation and amortization		**(11,091)**	(6,763)
Other taxes	(b)	**(6,251)**	11,854
Income taxes		**(9,823)**	(36,562)
Other income and deductions		**(10,431)**	26,760
Interest		**19,522**	38,530
Gridcom	(c)	**3,038**	1,440
Total changes		**8,367**	287,614
Current year net income		**$ 562,065**	$ 553,698

Notes to table:

(a) Amounts exclude Gridcom expenses and pass through items which are included in the electric margin calculation.

(b) Amounts exclude gross receipts taxes which are included in the electric and gas margin calculations.

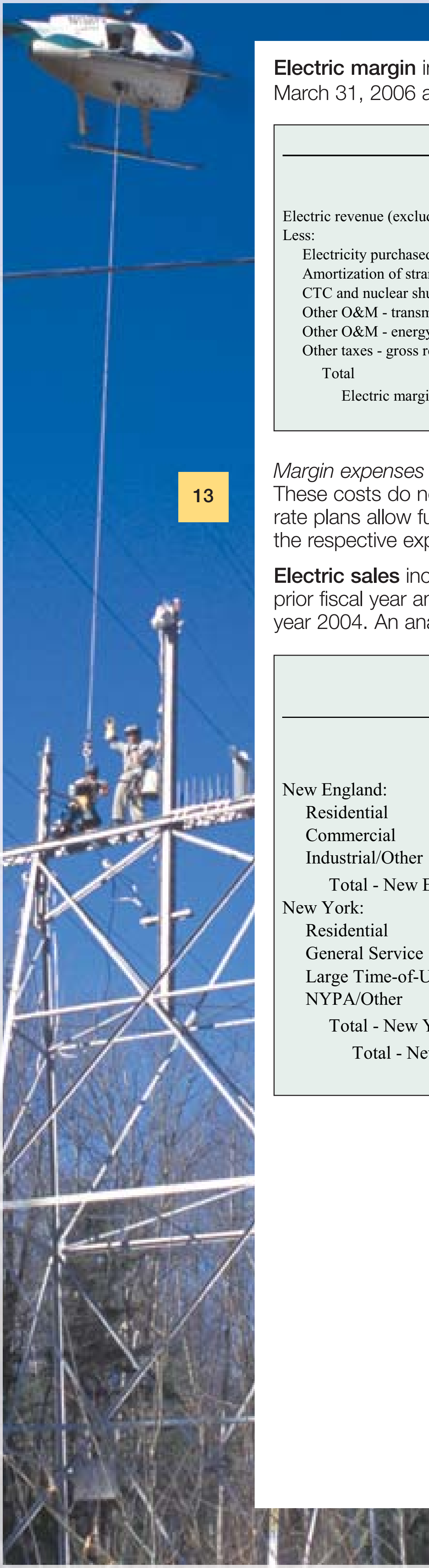
(c) Amounts represent the change in revenue and operating expenses in the Company's non-regulated telecommunications businesses.

For further discussion regarding each of the respective amounts identified above, please refer to the appropriate sections of this report that follow.

ELECTRIC

The Company's electricity business encompasses the transmission, distribution, and delivery of electricity including stranded cost recoveries. The Company's 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. Niagara Mohawk is responsible for the transmission, distribution, and sale of electricity.

The Company is no longer in the business of electricity generation and has divested 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 increased approximately $113 million and $2 million for the fiscal years ended March 31, 2006 and 2005, respectively. The table below details the components of these increases.

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

				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Electric revenue (excluding Gridcom)	**$ 7,142,154**	$ 6,236,188	$ 6,391,039	$ 905,966	*14.5*	$ (154,851)	*(2.4)*
Less:							
Electricity purchased	**3,544,029**	2,911,101	3,145,135	632,928	*21.7*	(234,034)	*(7.4)*
Amortization of stranded costs	**532,987**	318,844	264,824	214,143	*67.2*	54,020	*20.4*
CTC and nuclear shutdown charges	**73,364**	149,140	145,517	(75,776)	*(50.8)*	3,623	*2.5*
Other O&M - transmission wheeling	**167,885**	143,865	117,425	24,020	*16.7*	26,440	*22.5*
Other O&M - energy efficiency costs	**112,715**	111,498	112,817	1,217	*1.1*	(1,319)	*(1.2)*
Other taxes - gross receipts tax	**42,709**	46,058	51,592	(3,349)	*(7.3)*	(5,534)	*(10.7)*
Total	**4,473,689**	3,680,506	3,837,310	793,183	*21.6*	(156,804)	*(4.1)*
Electric margin	**$ 2,668,465**	$ 2,555,682	$ 2,553,729	$ 112,783	*4.4*	$ 1,953	*0.1*

Margin expenses

These costs do not impact electric margin or net income as the Company's applicable tariffs and rate plans allow full recovery of these costs from customers. For further discussion regarding each of the respective expense types, please refer to the appropriate sections of this report that follow.

Electric sales increased approximately 1,219 GWh (1.9%) in fiscal year 2006 as compared to the prior fiscal year and increased approximately 665 GWh (1.0%) in fiscal year 2005 compared to fiscal year 2004. An analysis by customer class is provided below.

Electric Sales Volumes (GWh)
Actual

				% Change	
	2006	2005	2004	FY06 vs FY05	FY05 vs FY04
New England:					
Residential	**12,276**	11,801	11,788	*4.0*	*0.1*
Commercial	**13,669**	13,313	13,126	*2.7*	*1.4*
Industrial/Other	**5,355**	5,438	5,455	*(1.5)*	*(0.3)*
Total - New England	**31,300**	30,552	30,369	*2.4*	*0.6*
New York:					
Residential	**11,486**	10,939	10,935	*5.0*	*0.0*
General Service	**11,488**	11,045	10,775	*4.0*	*2.5*
Large Time-of-Use	**6,908**	7,256	6,732	*(4.8)*	*7.8*
NYPA/Other	**5,109**	5,280	5,596	*(3.2)*	*(5.6)*
Total - New York	**34,991**	34,520	34,038	*1.4*	*1.4*
Total - New England and New York	**66,291**	65,072	64,407	*1.9*	*1.0*

The following table reflects weather normalized volumes.

Electric Sales Volumes (GWh)
Weather Normalized

	2006	2005	2004	% Change FY06 vs FY05	% Change FY05 vs FY04
New England:					
Residential	**12,027**	11,771	11,515	*2.2*	*2.2*
Commercial	**13,448**	13,303	13,015	*1.1*	*2.2*
Industrial/Other	**5,312**	5,440	5,434	*(2.4)*	*0.1*
Total - New England	**30,787**	30,514	29,964	*0.9*	*1.8*
New York:					
Residential	**11,210**	11,075	10,932	*1.2*	*1.3*
General Service	**11,319**	11,116	10,778	*1.8*	*3.1*
Large Time-of-Use	**6,877**	7,264	6,736	*(5.3)*	*7.8*
NYPA/Other	**5,109**	5,280	5,596	*(3.2)*	*(5.6)*
Total - New York	**34,515**	34,735	34,042	*(0.6)*	*2.0*
Total - New England and New York	**65,302**	65,249	64,006	*0.1*	*1.9*

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 offices, warehouses, retail, hotels, restaurants, hospitals/health, government and street lighting.
- Industrial 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.
- New York Power Authority (NYPA) 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 Company's service territories experienced more extreme weather temperatures during fiscal year 2006 (with higher than average temperatures in the summer months).

Weather had a positive impact on consolidated electric margin of approximately $24 million for the year ended March 31, 2006.

Economic impacts

During fiscal year 2006, the Company's service territories experienced one of the hottest summers on record. This swelled electricity deliveries by nearly 1.9% relative to the prior fiscal year. The summer also brought soaring energy prices after two hurricanes significantly affected operations of the U.S. oil and gas infrastructure in the Gulf of Mexico. The high energy prices, particularly during the second half of fiscal year 2006, caused a moderation of the New York and New England regional economies and a slowing of demand growth for electricity and natural gas.

Electric revenues increased approximately $906 million (14.5%) and decreased approximately $155 million (2.4%) for the fiscal years ended March 31, 2006 and 2005, respectively. The table below details components of these fluctuations.

Electric Revenue ($'s in 000's)

	Actual			FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Retail sales and deliveries							
Residential	**$ 3,095,154**	$ 2,708,421	$ 2,820,271	$ 386,733	*14.3*	$ (111,850)	*(4.0)*
Commercial	**2,374,474**	2,203,203	2,072,745	171,271	*7.8*	130,458	*6.3*
Industrial	**796,775**	726,295	743,761	70,480	*9.7*	(17,466)	*(2.3)*
Street lighting	**74,170**	77,423	71,869	(3,253)	*(4.2)*	5,554	*7.7*
Total retail sales	**6,340,573**	5,715,342	5,708,646	625,231	*10.9*	6,696	*0.1*
Sales for resale	**134,316**	126,706	223,789	7,610	*6.0*	(97,083)	*(43.4)*
Refund provisions	**34,802**	5,590	97,190	29,212	*522.6*	(91,600)	*(94.2)*
Other revenues	**632,463**	388,550	361,414	243,913	*62.8*	27,136	*7.5*
Total electric revenue (excluding Gridcom)	**$ 7,142,154**	$ 6,236,188	$ 6,391,039	$ 905,966	*14.5*	$ (154,851)	*(2.4)*

- Total retail sales for fiscal year 2006 increased $625 million compared to the prior fiscal year primarily due to an increase in purchased power costs. The Company, through various rate mechanisms, passes on to customers changes in its cost of purchased power.
- Sales for resale are revenues generated from selling electricity to other public utilities or municipal utilities. The $8 million increase in fiscal year 2006 compared to fiscal year 2005 is primarily due to NEP's resumption of the USGen contracts. 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 fiscal year ended March 31, 2005 was due to the expiration of some of these contracts.
- 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 over or under collection of prior period costs. In fiscal years 2006, 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.

- Other revenue consists of transmission wheeling revenue (revenue generated from transmitting electricity of other utilities over Company-owned transmission lines) and miscellaneous ancillary revenues. The increase of $244 million for the fiscal year ended March 31, 2006 from the prior fiscal year is due to (i) a $196 million increase in NEP's CTC deferral revenues due to the application of the proceeds received under the USGen settlement, (ii) a $32 million adjustment in Niagara Mohawk's electric revenue related to the recognition of a regulatory asset reflecting the Company's ability to recover a previously fully reserved accounts receivable, and (iii) other changes of $16 million.

Electricity purchased increased approximately $633 million (22%) for the fiscal year ended March 31, 2006 relative to the prior fiscal year. These costs represent the Company's cost to procure electricity for its customers who have not chosen an alternative energy supplier. The increase is primarily due to an increase in the price of electricity relative to the prior fiscal year. The increase is also attributable to the resumption of the obligation of certain long-term purchased power contracts that had been assumed by USGen when NEP had divested its generation assets in 1998. USGen declared bankruptcy and on April 1, 2005, the ongoing obligation of these contracts reverted back to NEP. These costs do not impact electric margin or net income as the Company's applicable tariffs and rate plans allow full recovery of these costs from customers.

Electricity purchased decreased approximately $234 million (7%) in the fiscal year ended March 31, 2005. The decrease in expense primarily related to New York and was 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.

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 decreased approximately $1.6 million (0.6 %) in the fiscal year ended March 31, 2006 and decreased approximately $4.6 million (1.5 %) in the fiscal year ended March 31, 2005. The table below details the components of these changes.

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

				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Gas revenue	**$ 1,037,081**	$ 808,015	$ 779,600	$ 229,066	*28.3*	$ 28,415	*3.6*
Less:							
Gas purchased	**741,419**	509,543	478,647	231,876	*45.5*	30,896	*6.5*
Other taxes - gross receipts tax	**8,049**	9,236	13,123	(1,187)	*(12.9)*	(3,887)	*(29.6)*
Gas margin	**287,613**	289,236	287,830	(1,623)	*(0.6)*	1,406	*0.5*
Gas revenue - state income tax adjustment	**-**	-	(5,957)	-	-	5,957	*(100.0)*
Gas margin after one-time item	**$ 287,613**	$ 289,236	$ 293,787	$ (1,623)	*(0.6)*	$ (4,551)	*(1.5)*

The $1.6 million decrease in gas margin comparing fiscal year 2006 to fiscal year 2005 is primarily due to a decline in margin from residential customers as a result of a decline in weather normalized use per customer. The decline in weather normalized use per customer is primarily due to customer conservation due to rising gas prices.

The $4.6 million decrease in gas margin after a one-time item comparing fiscal year 2005 to fiscal year 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 year 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 year 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 the Company subsequently reversed the over-accrual.

Gas throughput for the fiscal years ended March 31, 2006 and 2005, excluding transportation of customer-owned gas, decreased approximately 3.9 and 3.7 million dekatherms (Dth), respectively. An analysis by customer class is provided below.

Gas Throughput Volumes (000's of Dth)

Actual

				% Change	
	2006	2005	2004	FY06 vs FY05	FY05 vs FY04
Retail					
Residential	**42,840**	46,025	48,699	*(6.9)*	*(5.5)*
Commercial	**13,812**	14,579	15,479	*(5.3)*	*(5.8)*
Industrial	**420**	396	521	*6.1*	*(24.0)*
Other	**-**	1	2	*(100.0)*	*(50.0)*
Total retail	**57,072**	61,001	64,701	*(6.4)*	*(5.7)*
Transportation	**78,341**	80,329	83,548	*(2.5)*	*(3.9)*
Total gas throughput	**135,413**	141,330	148,249	*(4.2)*	*(4.7)*

Gas Throughput Volumes (000's of Dth)

Weather Normalized

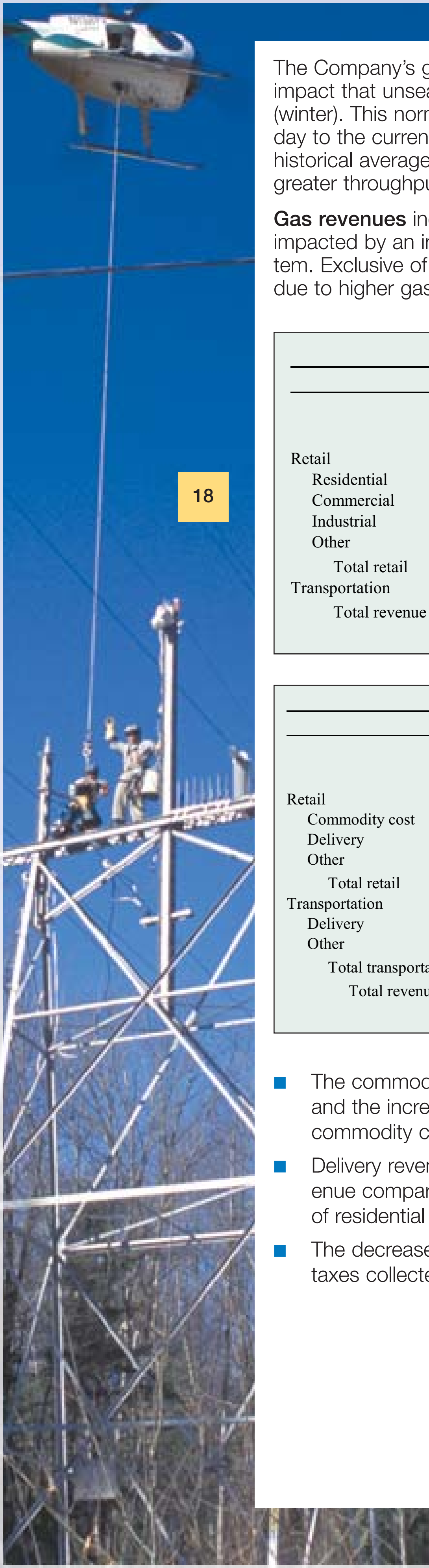
				% Change	
	2006	2005	2004	FY06 vs FY05	FY05 vs FY04
Retail					
Residential	**45,904**	46,105	47,995	*(0.4)*	*(3.9)*
Commercial	**14,672**	14,524	15,316	*1.0*	*(5.2)*
Industrial	**420**	396	521	*6.1*	*(24.0)*
Other	**-**	1	2	*(100.0)*	*(50.0)*
Total retail	**60,996**	61,026	63,834	*(0.0)*	*(4.4)*
Transportation	**79,755**	80,239	83,217	*(0.6)*	*(3.6)*
Total gas throughput	**140,751**	141,265	147,051	*(0.4)*	*(3.9)*

Retail
The decrease in retail throughput (for customers purchasing gas commodity from the Company rather than an alternative provider) comparing fiscal year 2006 to fiscal year 2005 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 for customers purchasing commodity from an alternate provider.

The decline in transportation throughput comparing fiscal year 2006 to fiscal year 2005 and fiscal year 2005 to fiscal year 2004 is primarily related to a decline in usage-per-customer of residential transportation customers offset by an increase in usage by larger transportation customers under special contracts. The increase in throughput for special customer contracts does not impact margin as the contract rates are to a large extent fixed in nature and these classes are subject to a true-up to a target which is set independently in the Company's rate case proceeding.

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 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 refund (due to greater throughput) the customer.

Gas revenues increased $229 million (28.3%) in the current fiscal year. This revenue increase is impacted by an increase in gas sold for resale to customers from the Company's distribution system. Exclusive of these off-system sales for resale, gas revenues increased $131 million primarily due to higher gas prices being passed through to the customers.

Revenue by Customer Type

($'s in 000's)

				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Retail							
Residential	**$ 617,058**	$ 521,593	$ 513,631	$ 95,465	*18.3*	$ 7,962	*1.6*
Commercial	**200,940**	160,768	154,806	40,172	*25.0*	5,962	*3.9*
Industrial	**4,892**	3,482	4,103	1,410	*40.5*	(621)	*(15.1)*
Other	**140,181**	44,479	26,670	95,702	*215.2*	17,809	*66.8*
Total retail	**963,071**	730,322	699,210	232,749	*31.9*	31,112	*4.4*
Transportation	**74,010**	77,693	80,390	(3,683)	*(4.7)*	(2,697)	*(3.4)*
Total revenue	**$ 1,037,081**	$ 808,015	$ 779,600	$ 229,066	*28.3*	$ 28,415	*3.6*

Revenue by Component

($'s in 000's)

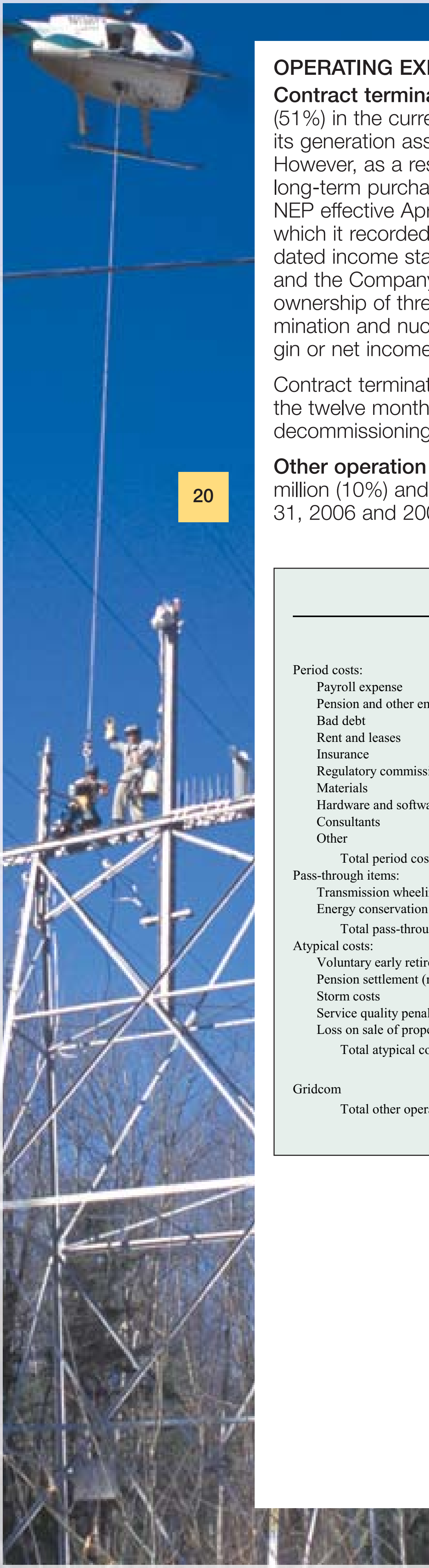
				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Retail							
Commodity cost	**$ 741,419**	$ 509,543	$ 478,647	$ 231,876	*45.5*	$ 30,896	*6.5*
Delivery	**200,509**	199,145	201,503	1,364	*0.7*	(2,358)	*(1.2)*
Other	**21,143**	21,634	19,060	(491)	*(2.3)*	2,574	*13.5*
Total retail	**963,071**	730,322	699,210	232,749	*31.9*	31,112	*4.4*
Transportation							
Delivery	**73,532**	76,959	79,415	(3,427)	*(4.5)*	(2,456)	*(3.1)*
Other	**478**	734	975	(256)	*(34.9)*	(241)	*(24.7)*
Total transportation	**74,010**	77,693	80,390	(3,683)	*(4.7)*	(2,697)	*(3.4)*
Total revenue	**$ 1,037,081**	$ 808,015	$ 779,600	$ 229,066	*28.3*	$ 28,415	*3.6*

- 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. The decrease in delivery revenue comparing fiscal year 2006 to fiscal year 2005 is primarily due to lower gas throughput of residential customers.
- The decrease in other gas revenue is primarily related to a decrease in the gross revenue taxes collected from customers as a result of a decline in the state imposed revenue tax rates.

Gas revenues increased $28 million (3.6%) in the fiscal year ended March 31, 2005. 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 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 increased approximately $232 million (45.5%) in the current fiscal year compared to the prior fiscal year. This increase is primarily due to an increase in the amount of gas sold for resale off-system. Purchased gas expense increased approximately $134 million after excluding the impacts of gas sold off system. This increase is primarily due to increased natural gas prices partially offset by decreased usage by customers. The Company's net cost per Dth, as charged to expense, increased to $9.92 in the fiscal year ended March 31, 2006 from $7.12 in the fiscal year ended March 31, 2005.

Gas purchased expense increased approximately $31 million (6.5%) in the fiscal year ended March 31, 2005 compared to the fiscal year ended March 31, 2004. 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 fiscal year ended March 31, 2005 from $6.61 in the prior fiscal year. This increase in price was slightly offset by decreased purchases.



OPERATING EXPENSES

Contract termination and nuclear unit shutdown charges decreased approximately $76 million (51%) in the current fiscal year. As part of generation deregulation in New England, NEP divested its generation assets, which included the transfer of long-term purchased power contracts. However, as a result of the bankruptcy of USGen (the entity that assumed the obligation of those long-term purchase power contracts) the ongoing obligation of those contracts reverted back to NEP effective April 1, 2005. Prior to April 1, NEP had been making a monthly payment to USGen which it recorded to the contract termination and nuclear unit shutdown charges on the consolidated income statement. The Company's CTC reflects the above market costs of the contracts 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.

Contract termination and nuclear shutdown charges increased approximately $4 million (3%) in the twelve months ended March 31, 2005. The increase is primarily due to an increase in nuclear decommissioning costs in fiscal 2005 compared with the prior fiscal year.

Other operation and maintenance expense for the Company increased approximately $134 million (10%) and decreased approximately $221 million (14%) for the fiscal years ended March 31, 2006 and 2005, respectively. The table below details components of these fluctuations.

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

				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Period costs:							
Payroll expense	**$ 429,612**	$ 448,282	$ 490,319	$ (18,670)	*(4.2)*	$ (42,037)	*(8.6)*
Pension and other employee benefits	**183,637**	172,942	201,411	10,695	*6.2*	(28,469)	*(14.1)*
Bad debt	**74,158**	69,875	85,028	4,283	*6.1*	(15,153)	*(17.8)*
Rent and leases	**45,616**	38,045	37,434	7,571	*19.9*	611	*1.6*
Insurance	**43,947**	34,954	46,441	8,993	*25.7*	(11,487)	*(24.7)*
Regulatory commission fees	**23,349**	24,729	22,507	(1,380)	*(5.6)*	2,222	*9.9*
Materials	**67,352**	57,442	55,947	9,910	*17.3*	1,495	*2.7*
Hardware and software	**26,616**	31,457	30,356	(4,841)	*(15.4)*	1,101	*3.6*
Consultants	**51,169**	56,715	48,603	(5,546)	*(9.8)*	8,112	*16.7*
Other	**190,919**	168,303	159,367	22,616	*13.4*	8,936	*5.6*
Total period costs	**1,136,375**	1,102,744	1,177,413	33,631	*3.0*	(74,669)	*(6.3)*
Pass-through items:							
Transmission wheeling	**167,885**	143,865	117,425	24,020	*16.7*	26,440	*22.5*
Energy conservation expenses	**112,715**	111,498	112,817	1,217	*1.1*	(1,319)	*(1.2)*
Total pass-through items	**280,600**	255,363	230,242	25,237	*9.9*	25,121	*10.9*
Atypical costs:							
Voluntary early retirement program	**-**	(25,112)	116,857	25,112	*(100.0)*	(141,969)	*(121.5)*
Pension settlement (recovery)/losses	**-**	(14,485)	23,144	14,485	*(100.0)*	(37,629)	*(162.6)*
Storm costs	**17,054**	1,371	5,700	15,683	*1,143.9*	(4,329)	*(75.9)*
Service quality penalties	**10,446**	4,400	2,000	6,046	*137.4*	2,400	*120.0*
Loss on sale of properties	**-**	7,200	-	(7,200)	*(100.0)*	7,200	*100.0*
Total atypical costs	**27,500**	(26,626)	147,701	54,126	*(203.3)*	(174,327)	*(118.0)*
Gridcom	**35,891**	15,203	12,510	20,688	*136.1*	2,693	*21.5*
Total other operating and maintenance	**$ 1,480,366**	$ 1,346,684	$ 1,567,866	$ 133,682	*9.9*	$ (221,182)	*(14.1)*

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.

- The decrease in payroll expense for the fiscal year ended March 31, 2006 is primarily due to ongoing headcount reductions. Payroll expense decreased during the fiscal year ended March 31, 2005 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 pension and other employee benefits in the fiscal year ended March 31, 2006 is primarily due to a lower return on plan assets.
- The increase in bad debt expense in the fiscal year ended March 31, 2006 is primarily due to increased commodity costs and accounts receivable. The decrease in bad debt expense for the fiscal year ended March 31, 2005 was mainly the result of improved collections at Niagara Mohawk.
- The increase in rent and leases in the fiscal year ended March 31, 2006 is primarily due to an increase in new information technology systems going into service.
- The increase in insurance expense in the fiscal year ended March 31, 2006 is primarily due to an increase in the Company's insurance accruals for workers compensation and third party claims. Insurance expense decreased in the fiscal year ended March 31, 2005 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.
- Material expenses increased in the fiscal year ended March 31, 2006 relative to the prior fiscal year primarily due to system reliability spending.
- Regulatory commission fees are fees paid to the FERC and the state utility commissions having jurisdiction.
- The increase in other for the fiscal year ended March 31, 2006 is primarily due to an increase in third party contractor expenses related to distribution system reliability spending (tree trimming, site maintenance, etc.).

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.

- Transmission wheeling expenses (transmitting Company electricity over transmission lines owned by other utilities) are recoverable through NEP's and Niagara Mohawk's rate agreements.
- 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.

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

- 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 of approximately $23 million of its pension and post retirement benefit obligations other than pension cost that had been expensed in fiscal year 2004.
- 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 PSC for recovery for $21 million of the pension settlement loss that was recorded to expense in fiscal 2004.
- Storm costs represent excessive repairs and power restoration costs beyond normal storm costs. These storm costs are not recoverable through rates.
- The Company is subject to service quality standards with respect to reliability and certain aspects of customer service and safety. The Company works toward service quality standards that the state regulators expect the Company to achieve. If the Company falls below a prescribed standard, a penalty is incurred.
- 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.

Gridcom
These costs relate to the Company's non-regulated telecommunications businesses which provide telecommunications infrastructure and related services. Expenses increased $21 million for the fiscal year ended March 31, 2006 relative to the prior fiscal year due to (i) an increase in office supplies – $6 million, (ii) increase in outside services (engineering, professional support, etc.) related to a project for Sprint/Nextel – $12 million, (iii) increase in rents – $2 million, and (iv) other increases of $1 million.

Depreciation and amortization increased $11 million for the fiscal year ended March 31, 2006 relative to the prior fiscal year because capital projects, including new information technology systems, went into service. For the fiscal year ended March 31, 2005, depreciation and amortization expense remained constant relative to the prior fiscal year.

Amortization of stranded costs increased approximately $214 million (67%) and $54 million (20%) for the fiscal years ended March 31, 2006 and 2005, 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. Approximately $196 million of the $214 million increase during fiscal year 2006 is due to NEP's resumption on April 1, 2005 of the performance and payment obligations under power supply contracts that had previously been transferred to USGen. The performance and payment obligations do not affect the results of operations, as the Company will recover the above market cost of the contracts from customers through the CTC.

The remaining $18 million increase relative to the prior fiscal year primarily relates to Niagara Mohawk's Merger Rate Plan. Under the Merger Rate Plan, the stranded cost regulatory asset amortization period was established for recovery over the ten year period ending December 31, 2011. This asset is being amortized unevenly on an increasing, graduated schedule.

Other taxes increased approximately $2 million (0.5%) and decreased approximately $21 million (6%) for the fiscal years ended March 31, 2006 and 2005, respectively. The table below details components of this fluctuation.

Other taxes ($'s in 000's)

				FY06 vs FY05		FY05 vs FY04	
	2006	2005	2004	$ Change	% Change	$ Change	% Change
Property taxes							
New England - electric	**$ 67,166**	$ 61,382	$ 70,188	$ 5,784	*9.4*	$ (8,806)	*(12.5)*
New York - electric	**137,329**	133,720	129,490	3,609	*2.7*	4,230	*3.3*
New York - gas	**34,332**	33,457	32,759	875	*2.6*	698	*2.1*
Total property taxes	**238,827**	228,559	232,437	10,268	*4.5*	(3,878)	*(1.7)*
Gross receipts tax							
New England - electric	**33,403**	30,027	29,735	3,376	*11.2*	292	*1.0*
New York - electric	**9,306**	16,031	21,857	(6,725)	*(41.9)*	(5,826)	*(26.7)*
New York - gas	**8,049**	9,236	13,123	(1,187)	*(12.9)*	(3,887)	*(29.6)*
Total gross receipts taxes	**50,758**	55,294	64,715	(4,536)	*(8.2)*	(9,421)	*(14.6)*
Other	**34,389**	38,406	46,382	(4,017)	*(10.5)*	(7,976)	*(17.2)*
Total other taxes	**$ 323,974**	$ 322,259	$ 343,534	$ 1,715	*0.5*	$ (21,275)	*(6.2)*

Property taxes increased $10.3 million (4.5%) in the fiscal year ended March 31, 2006. This is primarily due to the fact that the fiscal year 2005 property tax expense includes a non-recurring property tax refund. The change in property tax expense from fiscal year 2004 thru fiscal year 2006 is more typical with property tax expense increasing $6.4 million, or about 2.7%, over two years.

The Property Tax department has implemented an aggressive program to reduce and control the Company's property tax liability. Underlying property tax rates and levies have increased significantly over the past four years because of rising municipal and school spending. For example, tax rates in NY have increased by over 42% over this period. However, because of these tax mitigation strategies, the Company's property tax liability has increased only 9.9% during the same timeframe.

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.

Other is comprised of payroll taxes, unemployment taxes and sales and use taxes. The decrease in fiscal year 2006 and 2005 is primarily due to reduction in payroll taxes due to headcount reductions. Payroll taxes consist of the employer's portion of social security and Medicare taxes.

Income taxes increased approximately $10 million (3%) for the fiscal year ended March 31, 2006 from the prior fiscal year primarily due to higher pre-tax book income.

Income taxes increased approximately $37 million (14%) for the fiscal year ended March 31, 2005 from the prior fiscal year 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 decreased $10 million (184%) in fiscal 2006. This is primarily attributable to an $8 million favorable adjustment to non-utility related income taxes at Niagara Mohawk which were recorded in the 2005 fiscal year with no similar adjustments recorded in the 2006 or 2004 fiscal years.

Interest expense decreased $20 million (7%) and $39 million (12%) for the fiscal years ended March 31, 2006 and 2005, respectively. The decreases are primarily due to maturing long-term debt 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, 2006, the Company's principal sources of liquidity included cash and cash equivalents of approximately $216 million and accounts receivable of approximately $1.3 billion. The Company has a negative working capital balance of $43 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 $711 million.

Operating Activities

Net cash provided by operating activities decreased $2 million for the fiscal year ended March 31, 2006 from the prior fiscal year. The decrease is primarily due to the following:

- Reduction in provision for deferred income taxes of $176 million primarily due to the expiration in December 2004 of federal bonus depreciation.
- Increased accounts receivable of $186 million primarily due to the higher costs of electricity and gas passed along to customers.
- Increased materials and supplies of $25 million primarily due to the higher cost of stored gas and the lower volume of gas sold relative to the prior fiscal year because of milder winter temperatures.

These were offset by:

- Increased depreciation and amortization of $11 million due to capital projects, including new information technology systems, going into service.
- Increased stranded cost recovery of $214 million due to (i) the resumption of the USGen agreements and (ii) in accordance with Niagara Mohawk's merger rate plan.
- Decrease in purchase power obligations payments of $95 million due to the resumption of the USGen agreements.
- Increased accounts payable and accrued expenses and an increase in accrued interest and taxes of $143 million primarily due to an increase in accrued taxes of $127 million.

Investing Activities

Net cash used in investing activities increased approximately $171 million in the current fiscal year. This increase was primarily due to an increase in construction additions and an increase in restricted cash. Capital expenditures increased approximately $88 million during fiscal year 2006 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. Restricted cash increased $67 million primarily due to equity in hedge accounts related to the rise in underlying commodity prices.

Financing Activities

Net cash used in financing activities increased approximately $76 million for the fiscal year ended March 31, 2006 from the prior fiscal year. The primary reasons for the increase are:

- Increased reduction in short-term debt to affiliates of $278 million. In the prior fiscal years presented, the change in short-term debt to affiliates represented cash inflows.
- Decrease in dividends paid on common stock of $163 million.
- Decrease in the reduction of long term debt of $37 million.

LONG TERM

The Company's total capital requirements consist of amounts for its construction programs, electricity and gas purchases, working capital needs, and maturing debt issues. Generally, construction expenditure levels for the energy delivery business are consistent from year to year, however, the Company is embarking on a Reliability Enhancement Program, to improve performance and reliability, which will result in increased capital expenditures over the next five years.

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

	Payment due in:						
($'s in millions)	2007	2008	2009	2010	2011	Thereafter	Total
Long-term debt	$ 302	$ 207	$ 687	$ 357	$ 357	$ 1,720	$ 3,630
Electric purchase power commitments	2,319	1,384	1,304	1,017	158	2,741	8,923
Gas supply commitments	295	242	5	5	5	4	556
Derivative swap commitments*	247	246	44	-	-	-	537
Expected pension and post-retirement trust funding**	298	N/A	N/A	N/A	N/A	N/A	298
Interest on long-term debt***	123	102	71	46	48	N/A	390
Construction expenditures****	711	N/A	N/A	N/A	N/A	N/A	711
Total contractual cash obligations	$ 4,295	$ 2,181	$ 2,111	$ 1,425	$ 568	$ 4,465	$ 15,045

* Forecasted and actual amounts could differ due to changes in market conditions.
** These are expected contributions to Company's pension and post-retirement benefit plans' trusts, not the minimum funding requirement.
*** Forecasted and actual amounts could differ due to changes in market conditions. Amounts beyond five years are not forecasted and, therefore, are not included.
**** Represents budgeted amounts for which substantial commitments have been made. Amounts beyond 1 year are not contractual obligations and are therefore not included.

One of the Company's main objectives is to meet and/or exceed service quality goals. This objective will be realized by increasing customer satisfaction through a focus on improving service quality as the Company strives for the optimum performance and implementing a reliability enhancement program to improve service to the Company's customers. A significant increase in capital spending on the Company's infrastructure is under way in order to modernize it to attain service quality goals.

In line with the Company's reliability objective, in order to improve performance the Company has developed and begun execution of a five-year reliability enhancement program. The program is made up of four main categories of work:

- vegetation management – incremental tree trimming to address an increase in customer interruptions related to contacts with tree limbs;
- feeder hardening – upgrading the Company's worst-performing overhead electric circuits by replacing aged and deteriorated components and protecting against lighting strikes and animal contacts;
- asset replacement – replacing aging distribution equipment before its expected end of life, including poles, underground cable, and substation equipment; and
- inspection and maintenance – increasing our preventive maintenance and repair activities to find potential faults before they occur.

The planned capital investment over the next five years from these initiatives will be recovered from customers in accordance with the Company's rate plans. The remaining incremental operating costs are expected to be offset by efficiencies created within the business.

OTHER REGULATORY MATTERS

NEW YORK PSC MATTERS

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

Deferral account audit

On July 29, 2005, Niagara Mohawk filed its biannual CTC reset and deferral account recovery filing to reset rates charged to customers beginning January 1, 2006. Niagara Mohawk resets its CTC every two years under its Merger Rate Plan. The CTC reset is intended to account for changes in forecasted electricity and natural gas commodity prices, and the effects those changes have on Niagara Mohawk's above market payments under legacy power contracts that otherwise would be stranded.

In addition, the Merger Rate Plan allows Niagara Mohawk to recover amounts exceeding a $100 million base deferral threshold in its deferral account (as projected through the end of each two-year CTC reset period through the end of the Merger Rate Plan). In the July 29, 2005 filing, Niagara Mohawk included a proposal to recover the excess balance of the deferral account as of June 30, 2005 of $196 million ($296 million, less the $100 million base deferral threshold that continues through the end of the Merger Rate Plan) and a projection through the end of the two-year period of $373 million, producing a total projected recoverable balance of $569 million ($669 million, less the $100 million base deferral threshold as of December 31, 2007). On December 27, 2005, the New York PSC approved Niagara Mohawk's proposal for the new CTC effective January 1, 2006. The PSC also approved recovery of deferral account amounts of $100 million in calendar year 2006 and $200 million in calendar year 2007. For 2006, the deferral-related surcharge was included in rates beginning in April and the $100 million is being collected over the last nine months of the 2006 calendar year.

An audit of the deferral amount by the Department of Public Service Staff (Staff) has been ongoing for several months and a formal hearing process has been established before a hearing officer at the PSC to litigate the levels in the deferral account. On August 2, 2006, the Staff filed testimony on their initial recommended audit adjustments. In its testimony, the Staff proposed to disallow $165 million associated with the June 30, 2005 balance of $296 million and an additional $107 million through the end of the two-year period for a total disallowance of $272 million of the $669 million projected balance as of December 31, 2007. The Staff also indicated it had not completed its audit on other deferral account items, and that further proposed adjustments may be offered. In addition, the Staff proposed to require the write-off of all of the $1.2 billion of goodwill on Niagara Mohawk's balance sheet associated with the Niagara Mohawk's acquisition by National Grid. Because goodwill is excluded from Niagara Mohawk's investment base for ratemaking purposes, the Staff's position on goodwill has no impact on the Niagara Mohawk's future rates. Niagara Mohawk disagrees with the Staff's proposed adjustments to the deferral account and to goodwill. Niagara Mohawk has filed testimony in response, and hearings are scheduled for October 2006. Despite the Staff's testimony, Niagara Mohawk continues to believe that its accounting for the deferrals is appropriate and will continue to defer costs and revenues, as applicable, through the end of the Merger Rate Plan on December 31, 2011, subject to regulatory review and approval.

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 Note F – "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 is earning a rate of return of at least 6.60% (nominal) on the $209 million of funding through December 31, 2011 and is eligible to earn 80% of the amount by which the rate of return on the pension and post-retirement benefit funds exceeds 5.34% (nominal) measured as of that date.

CONSOLIDATED FINANCIAL STATEMENTS

- Report of Independent Registered Public Accounting Firm
- Consolidated Statements of Income and Consolidated Statements of Comprehensive Income for the years ended March 31, 2006, 2005 and 2004
- Consolidated Statements of Retained Earnings for the years ended March 31, 2006, 2005 and 2004
- Consolidated Balance Sheets at March 31, 2006 and 2005
- Consolidated Statements of Cash Flows for the years ended March 31, 2006, 2005 and 2004
- Notes to 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2006 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

New York, NY
June 29, 2006

NATIONAL GRID USA AND SUBSIDIARY COMPANIES

Consolidated Statements of Income

(In thousands of dollars)

	For the years ended March 31,		
	2006	2005	2004
Operating revenues:			
Electric	**$ 7,193,299**	$ 6,263,607	$ 6,414,325
Gas	**1,037,081**	808,015	779,600
Total operating revenues	**8,230,380**	7,071,622	7,193,925
Operating expenses:			
Purchased energy:			
Electricity purchased	**3,544,029**	2,911,101	3,145,135
Gas purchased	**741,419**	509,543	478,647
Contract termination charges and nuclear unit shutdown charges	**73,364**	149,140	145,517
Other operation and maintenance	**1,480,366**	1,346,684	1,567,866
Depreciation and amortization	**393,849**	382,758	375,995
Amortization of stranded costs	**532,987**	318,844	264,824
Other taxes	**323,974**	322,259	343,534
Income taxes	**316,052**	306,229	269,667
Total operating expenses	**7,406,040**	6,246,558	6,591,185
Operating income	**824,340**	825,064	602,740
Other income (deductions), net	**(4,756)**	5,675	(21,085)
Operating and other income	**819,584**	830,739	581,655
Interest:			
Interest on long-term debt	**172,740**	207,791	263,616
Other interest	**84,779**	69,250	51,955
Total interest expense	**257,519**	277,041	315,571
Net income	**$ 562,065**	$ 553,698	$ 266,084

Consolidated Statements of Comprehensive Income

(In thousands of dollars)

	For the years ended March 31,		
	2006	2005	2004
Net income	**$ 562,065**	$ 553,698	$ 266,084
Other comprehensive income:			
Unrealized gains on securities, net of taxes	**6,217**	2,858	7,982
Hedging activity, net of taxes	**4,009**	(4,629)	2,425
Change in additional minimum pension liability, net of taxes	**182,489**	14,557	67,292
Reclassification adjustment for gains included in net income, net of taxes	**(24,810)**	(7,102)	(525)
Total other comprehensive income	**167,905**	5,684	77,174
Comprehensive income	**$ 729,970**	$ 559,382	$ 343,258

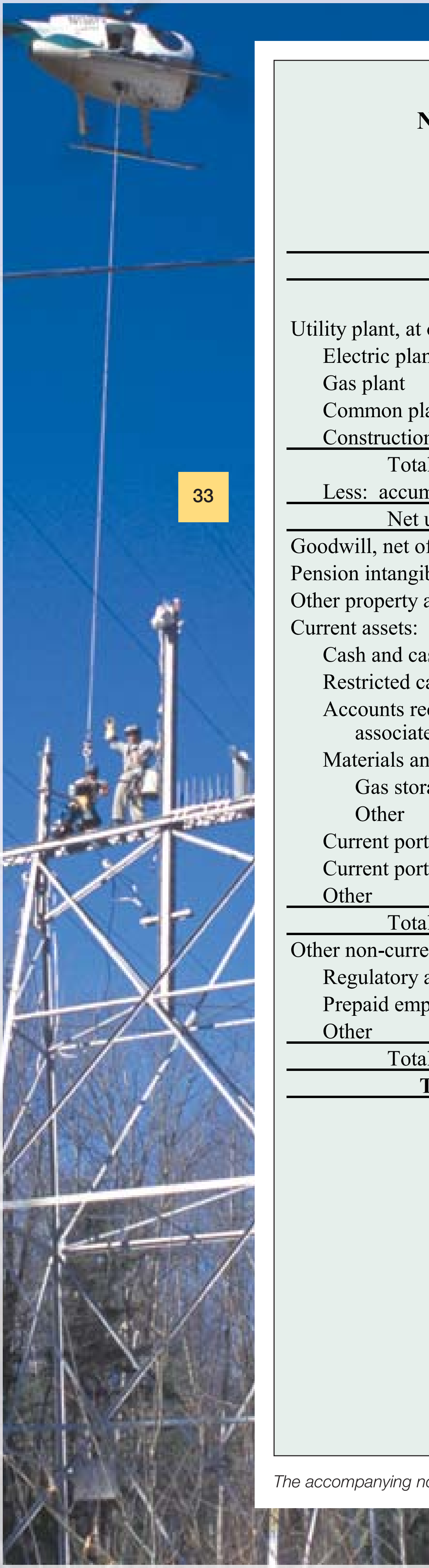
The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Retained Earnings

(In thousands of dollars)

	For the years ended March 31,		
	2006	2005	2004
Retained earnings at beginning of period	**$ 980,101**	$ 648,255	$ 388,454
Net income	**562,065**	553,698	266,084
Dividends on preferred stock	**(2,210)**	(3,461)	(5,095)
Dividends on common stock	**(55,000)**	(218,100)	-
Loss on redemption of preferred stock	**-**	-	(1,194)
Other	**(359)**	(291)	6
Retained earnings at end of period	**$ 1,484,597**	$ 980,101	$ 648,255

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,	
	2006	2005
ASSETS		
Utility plant, at original cost:		
Electric plant	**$ 10,921,706**	$ **10,531,420**
Gas plant	**1,568,845**	1,517,804
Common plant	**382,167**	378,418
Construction work-in-process	**339,644**	175,879
Total utility plant	**13,212,362**	12,603,521
Less: accumulated depreciation and amortization	**(4,238,319)**	(3,972,348)
Net utility plant	**8,974,043**	8,631,173
Goodwill, net of amortization	**3,204,970**	3,237,049
Pension intangible	**36,885**	54,888
Other property and investments	**425,681**	412,637
Current assets:		
Cash and cash equivalents	**216,132**	354,578
Restricted cash	**80,265**	15,288
Accounts receivable (less reserves of $149,492 and associated companies of $11,571 and $6,806, respectively)	**1,336,661**	1,117,729
Materials and supplies, at average cost:		
Gas storage	**23,576**	3,498
Other	**48,788**	42,602
Current portion of accumulated deferred income taxes	**197,209**	340,837
Current portion of regulatory assets	**393,213**	361,158
Other	**66,202**	88,455
Total current assets	**2,362,046**	2,324,145
Other non-current assets:		
Regulatory assets	**5,264,789**	5,981,172
Prepaid employee pension benefits	**360,183**	-
Other	**53,094**	70,875
Total non-current assets	**5,678,066**	6,052,047
Total assets	**$ 20,681,691**	$ 20,711,939

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, 2006	March 31, 2005
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	**1,484,597**	980,101
Accumulated other comprehensive loss	**(4,256)**	(172,161)
Total common stockholder's equity	**8,579,387**	7,906,986
Minority interest in subsidiaries	**17,712**	19,551
Cumulative preferred stock	**52,317**	52,317
Long-term debt	**2,125,241**	2,464,058
Long-term debt to affiliates	**1,200,000**	1,200,000
Total capitalization	**11,974,657**	11,642,912
Current liabilities:		
Accounts payable	**619,501**	588,200
Customers' deposits	**40,770**	34,061
Accrued interest	**50,506**	70,979
Short-term debt due to affiliates	**644,168**	687,168
Current portion of long-term debt	**302,320**	567,725
Current portion of accrued Yankee nuclear plant costs	**54,796**	53,114
Current portion of derivatives and swap contracts	**324,858**	203,558
Current portion of purchased power obligations	**13,559**	104,486
Other	**354,486**	198,881
Total current liabilities	**2,404,964**	2,508,172
Other non-current liabilities:		
Accumulated deferred income taxes	**2,222,954**	2,204,833
Unamortized investment tax credits	**67,593**	74,331
Accrued Yankee nuclear plant costs	**140,832**	168,426
Purchased power obligations	**23,688**	189,126
Derivatives and swap contracts	**538,882**	415,394
Accrued employee pension and other benefits	**719,524**	701,995
Additional minimum pension liability	**127,351**	290,145
Environmental remediation costs	**569,319**	604,540
Nuclear fuel disposal costs	**150,642**	145,562
Regulatory liabilities	**1,355,595**	1,427,513
Other	**385,690**	338,990
Total other non-current liabilities	**6,302,070**	6,560,855
Total capitalization and liabilities	**$ 20,681,691**	$ 20,711,939

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

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

	For the years ended March 31, **2006**	2005	2004
Operating activities:			
Net income	**$ 562,065**	$ 553,698	$ 266,084
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**393,849**	382,758	375,995
Amortization of stranded costs	**532,987**	318,844	264,824
Provision for deferred federal and state income taxes and investment tax credits, net	**37,873**	213,955	143,604
Pension and other retirement benefit plan non-cash expense	**176,352**	168,689	281,471
Cash paid to pension and other retirement benefit plan trusts	**(188,616)**	(200,084)	(370,823)
Changes in operating assets and liabilities:			
Accounts receivable, net	**(218,932)**	(32,843)	(93,304)
Materials and supplies	**(26,264)**	(1,002)	(5,978)
Accounts payable and accrued expenses	**193,615**	58,301	(105,432)
Accrued interest and taxes	**(20,473)**	(28,754)	(63,192)
Pension and postretirement regulatory assets	**(18,813)**	3,472	(5,432)
Purchased power obligations	**(9,697)**	(104,694)	(111,621)
Other, net	**(59,726)**	24,083	(1,593)
Net cash provided by operating activities	**1,354,220**	1,356,423	574,603
Investing activities			
Construction additions	**(679,785)**	(592,160)	(552,293)
Sale of assets	**2,268**	7,649	11,977
Change in restricted cash	**(64,977)**	1,916	8,399
Other, net	**(39,729)**	(28,271)	(8,050)
Net cash used in investing activities	**(782,223)**	(610,866)	(539,967)
Financing activities			
Dividends paid on preferred stock	**(2,210)**	(3,461)	(5,095)
Dividends paid on common stock	**(55,000)**	(218,100)	-
Dividends paid on common stock of minority interests	**(3,822)**	(4,918)	(3,801)
Reductions in long-term debt	**(632,725)**	(669,267)	(1,812,085)
Proceeds from long-term debt	**28,000**	52,775	1,659,360
Redemption of preferred stock	**-**	(25,316)	(40,495)
Buyback of minority interest common stock	**(1,158)**	(6,730)	(3,454)
Net change in short-term debt to affiliates	**(43,000)**	234,732	273,134
Other, net	**(528)**	6,221	6
Net cash (used in) provided by financing activities	**(710,443)**	(634,064)	67,570
Net increase in cash and cash equivalents	**(138,446)**	111,493	102,206
Cash and cash equivalents, beginning of period	**354,578**	243,085	140,879
Cash and cash equivalents, end of period	**$ 216,132**	$ 354,578	$ 243,085
Supplemental disclosures of cash flow information:			
Interest paid	**$ 279,224**	$ 285,578	$ 366,489
Taxes paid	**157,250**	108,129	188,608

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 with regulated subsidiaries engaged in the transmission, distribution, and sale of electricity and natural gas. The Company is a wholly owned subsidiary of National Grid plc. 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 (Narragansett). 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.

The Company owns approximately 53.7% 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 in the Hydro Transmission companies, which represent the minority stockholders' proportionate share of the equity and is separately disclosed on the Company's consolidated balance sheet and the proportionate share of income is included in 'Other income (deductions), net' on the Company's statements of income.

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

3. Use of Estimates:
The preparation of financial statements in conformity with US GAAP requires management to make estimates that affect the reported amounts of assets and liabilities and 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 must 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." Niagara Mohawk files reports with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended.

5. Goodwill:

National Grid plc's acquisitions of the Company's subsidiaries including the 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, 2006 and 2005, 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, 2006, management determined that no adjustment to the goodwill carrying value was required. During fiscal year 2006, the Company made adjustments to reduce goodwill by approximately $32 million. This amount primarily related to (i) an adjustment to Niagara Mohawk goodwill of $9 million due to the settlement of an Internal Revenue Service (IRS) audit of pre-merger years related to a pre-merger tax contingency and (ii) an adjustment to Massachusetts Electric Company (Massachusetts Electric), Narragansett, and NEP goodwill of $15 million, $7 million and $1 million respectively, which related to the reclassification of long-term balance sheet accounts.

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 unbilled revenue included in accounts receivable at March 31, 2006 and 2005 was approximately $288 million and $243 million, respectively. 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 Company recognizes changes in unbilled electric revenues in its results of operations. Pursuant to Niagara Mohawk's 2000 multi-year gas settlement (which ended December 2004, with Niagara Mohawk having the right to request a change in rates at any time, if needed), changes in accrued unbilled gas revenues are deferred. At March 31, 2006 and 2005, approximately $6 million and $7 million, respectively, of unbilled gas revenues remain unrecognized in results of operations. Management 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 Company capitalizes AFUDC as part of construction costs in amounts equivalent to the cost of funds devoted to plant under construction for its regulated businesses. AFUDC represents the composite interest and equity costs of capital funds used to finance that portion of construction costs not yet eligible for inclusion in rate base. AFUDC is capitalized in "Utility plant" with offsetting non-cash credits to "Other income (deductions), net" and "Other 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 6.2%, 4.8% and 4.5% for the years ended March 31, 2006, 2005 and 2004, 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 federal and state utility commissions. The provision for depreciation as a percentage of weighted average depreciable property (excluding construction work-in-progress) was 3.04%, 3.05% and 3.1% for the fiscal years ended March 31, 2006, 2005, and 2004 respectively.

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 workers' compensation premium deposits. The $65 million increase in restricted cash for the fiscal year ended March 31, 2006 was primarily due to increased equity in hedge accounts related to the rise in underlying commodity prices.

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. In total, $38 million was deposited 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. As of March 31, 2006, the Company used $27.9 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:
Regulated federal and state income taxes are recorded under the provisions of SFAS No. 109 "Accounting for Income Taxes." Income taxes have been computed utilizing the asset and liability approach, 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 G – "Income Taxes"). Deferred income tax credits are amortized over the useful life of the underlying property.

13. Derivatives:
The Company accounts for derivative financial instruments under SFAS No. 133, "Accounting for Derivatives and Hedging Activities," and SFAS No. 149, "Amendment of SFAS No. 133 on Derivative Instruments and Hedging Activities," as amended. Under the provisions of SFAS No. 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 125% of the changes in fair value or cash flows of the hedged item. The Company also has purchase power agreements with non-affiliates for the purchase of power and capacity for resale to its retail customers. These agreements generally have no notional amounts and do not meet the definition of a derivative under SFAS No. 133.

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:
Additional minimum pension liability (AML) is recognized under SFAS No. 87, "Employers' Accounting for Pensions." Consistent with current rate agreements, Niagara Mohawk recovers all costs associated with its qualified pension plan due to the nature of its rate plan and has recorded a regulatory asset as an off-set to the qualified plan AML. The AML for the non-qualified plan is off-set through an adjustment to accumulated other comprehensive income.

The additional minimum pension liability for the Company's other subsidiaries is recognized in the balance sheet as a liability with an offsetting charge to other comprehensive income.

16. New Accounting Standards:
SFAS 123R
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 (APB) 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 on April 1, 2006 did 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 SFAS 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.

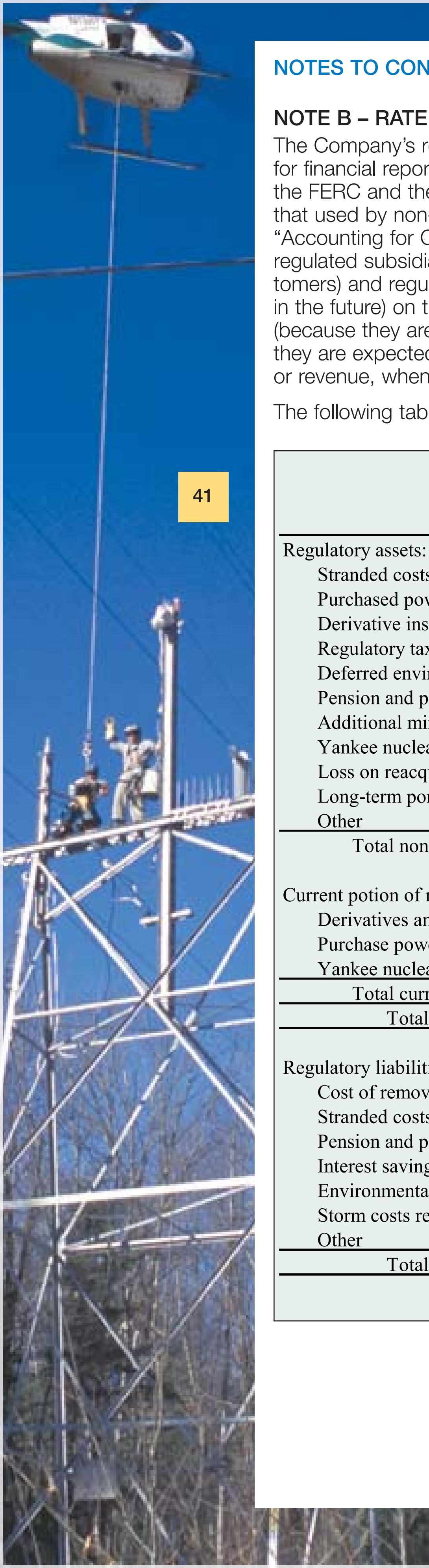
This statement is effective for the Company as of its March 31, 2006 fiscal year end. The Company recorded a $13 million asset retirement obligation reserve as of March 31, 2006 which is not material to the Company's results of operations or its financial position.

SFAS 154
In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3." Previously APB No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements," defined the requirements for the accounting and the reporting of a change in accounting principle. SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, SFAS No. 154 requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings for that period rather than being reported in an income statement.

SFAS No. 154 becomes effective for fiscal years ending after December 15, 2005. The Company adopted it as of its March 31, 2006 fiscal year.

FASB Exposure Draft on Pension and Other Post-retirement Benefits
On March 31, 2006, the FASB issued an Exposure Draft of proposed rules on employers' accounting for defined benefit pensions and other post-retirement benefit plans that would require employers to fully recognize the plan's funded status on the balance sheet. If adopted as proposed, the new rules would be applied retroactively to prior financial statements presented and be effective for fiscal years ending after December 15, 2006. The new rules, if adopted as proposed, may significantly increase the Company's recorded pension and other postretirement liabilities. NEP and Niagara Mohawk, as set forth in each of their respective current rate agreements, would recover the additional pension costs from customers and therefore the costs would be recognized as a regulatory asset upon adoption. The comment period on this Exposure Draft ended on May 31, 2006. The Company is currently evaluating the Exposure Draft and at this time cannot determine the full impact that the potential requirements of the Exposure Draft may have on its financial statements.

17. Reclassifications:
Certain amounts from prior years have been reclassified on the accompanying consolidated financial statements to conform to the fiscal 2006 presentation. The Company's consolidated financial statements for the fiscal year ended March 31, 2006 included out-of-period adjustments. The out-of-period adjustments had an immaterial impact on reported net income for the fiscal year ended March 31, 2006. These adjustments were recorded in fiscal year 2006 because they did not meet the materiality threshold for prior period restatement.



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." In accordance with SFAS No. 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.

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

($'s in 000's)	At March 31, 2006	2005
Regulatory assets:		
Stranded costs	**$ 2,478,018**	$ 2,997,281
Purchased power	**114,829**	382,955
Derivative instruments	**506,328**	415,394
Regulatory tax asset	**148,678**	120,521
Deferred environmental restoration costs	**563,871**	594,283
Pension and post-retirement benefit plans costs	**550,179**	531,366
Additional minimum pension liability (see Note F)	**79,923**	252,218
Yankee nuclear decommissioning costs	**140,832**	168,426
Loss on reacquired debt	**78,966**	87,645
Long-term portion of standard offer under-recovery of fuel costs	**46,803**	42,420
Other	**556,362**	388,663
Total non-current regulatory assets	**5,264,789**	5,981,172
Current potion of regulatory assets:		
Derivatives and swap contracts	**324,858**	203,558
Purchase power buyout costs	**13,559**	104,486
Yankee nuclear decommissioning costs	**54,796**	53,114
Total current portion of regulatory assets	**393,213**	361,158
Total regulatory assets	**$ 5,658,002**	$ 6,342,330
Regulatory liabilities:		
Cost of removal reserve (see Note K)	**$ (537,526)**	$ (504,819)
Stranded costs and CTC related	**(123,105)**	(209,291)
Pension and post-retirement plans fair value deferred gain	**(234,754)**	(228,138)
Interest savings deferral	**(92,534)**	(92,534)
Environmental response fund and insurance recoveries	**(81,673)**	(82,012)
Storm costs reserve	**(39,391)**	(33,681)
Other	**(246,612)**	(277,038)
Total regulatory liabilities	**$ (1,355,595)**	$ (1,427,513)

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 SFAS No. 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 SFAS No. 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: NEP is a participating transmission owner (PTO) in New England's RTO which commenced operations effective February 1, 2005. ISO New England, Inc. 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 return on common equity (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 ROE of 12.8%, subject to refund, plus an additional 0.5% incentive return on regional network service (RNS) rates that FERC approved in March 2004. 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. In June and July 2005, parties to the proceeding filed two rounds of briefs in response to the initial decision and opposing one another's positions. New England transmission owners continue to request a base ROE of 11.8% for all facilities before adding the .5% RTO participation adder and the 1% adder applicable to new transmission investment. Other parties are proposing a base ROE ranging from 9.14% to 10.64%, with some parties proposing to allow the 1% adder only for a small subset of projects and others proposing that the 1% adder is not justified under any circumstances.

The parties continue to await a final decision by the FERC. Related proceedings have concluded in the US Court of Appeals and the parties are similarly awaiting a decision from the Court.

Niagara Mohawk

Niagara Mohawk's electricity delivery rates are governed by a ten-year rate plan that began on February 1, 2002. Under the plan, after reflecting Niagara Mohawk's share of savings related to the acquisition, Niagara Mohawk may earn a threshold ROE of 10.6%, up to 11.75% without any sharing with customers (12.0% if certain customer outreach, education, competition related and low income incentive targets are met). Half of any amounts in excess of 12%, up to 14%, 25% of any earnings in excess of that up to 16% and 10% beyond that are retained by the Company. This effectively offers Niagara Mohawk the potential to achieve a ROE in excess of the regulatory allowed return of 10.6%. The ROE is calculated cumulatively from inception to December 31, 2005 and annually thereafter for the prior two calendar years. 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. 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. Niagara Mohawk may earn a threshold ROE ranging from 10.6% to 12.6% depending on the achievement of certain customer migration levels and customer awareness and understanding of gas competitive opportunities. Above this threshold, the revenue equivalent of gas earnings must be shared equally between shareholders and customers.

On July 29, 2005, Niagara Mohawk filed its biannual CTC reset and deferral account recovery filing to reset rates charged to customers beginning January 1, 2006. In the July 29, 2005 filing, Niagara Mohawk included a proposal to recover the excess balance of the deferral accounts as of June 30, 2005 of $196 million and a projection through the end of the two year period of $373 million. On December 27, 2005, the Public Service Commission (PSC) approved Niagara Mohawk's proposal for the new CTC effective January 1, 2006. The PSC also approved the recovery of deferral account amounts of $100 million in calendar year 2006 and $200 million in calendar 2007. For 2006, the actual deferral-related surcharge began in April 2006 and the full $100 million will be collected over the last nine months of the 2006 calendar year. An audit of the deferral amount by the Department of Public Service Staff (DPS Staff) is ongoing. A formal hearing process has been established before a hearing officer at the PSC to litigate the levels in the deferral account. Under the hearing schedule, the Staff will be filing testimony setting forth its initial adjustments in early August. Niagara Mohawk will continue to defer costs and revenues, as applicable, through the end of the Plan on December 31, 2011. Niagara Mohawk's future filings for recovery of deferred amounts are subject to regulatory review and approval.

Massachusetts Electric Company and Nantucket Electric Company

Under Massachusetts Electric's long-term rate plan, which runs until May 2020, there is no cap on earnings and no earnings sharing reflected in distribution rates until 2010. From May 2000 until February 2005, distribution rates were frozen. In March 2005, a settlement credit in the Massachusetts Electric's rates expired, which represents an increase of $10.7 million in pre-tax income through February 2006. Beginning in March 2006, distribution rates are to be adjusted each March until 2009 by the annual percentage change in average electricity distribution rates in the northeastern United States. Regulators approved the first such annual increase in the amount of $19.7 million, effective March 1, 2006. In 2009, actual earned savings will be determined and Massachusetts Electric 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 before tax. Earned savings represent the difference between a test year's distribution revenue and Massachusetts Electric's cost of providing service during the same test year, 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 Massachusetts Electric as well as the recovery of certain supply-related costs. For Massachusetts Electric, the settlement provided for (i) deferred rate recovery of about $66 million of power supply-related costs (of which $44.9 million has been recognized on the balance sheet at March 31, 2006), 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 pursuant to a merger agreement and rate plan implemented at the time of the Company's merger with Eastern Utilities Associates, distribution rates were frozen and Narragansett was permitted to retain 100% of its earnings up to an allowed ROE of 12%. Narragansett kept 50% of earnings between 12% and 13%, and 25% of earnings in excess of 13%. Under a new long-term rate plan, effective from November 2004 until December 2009, Narragansett Electric agreed to reduce its distribution rates by $10.2 million (pre-tax) per year. Beginning in January 2005, Narragansett has been 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 demonstrated savings subsequent to the acquisition of Eastern Utilities Associates in 2000. 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. This regulatory mechanism offers the potential to achieve returns in excess of traditional regulatory allowed returns.

In addition, Narragansett has implemented a customer credit totaling $27.6 million on most of its customers' bills from November 2004 through December 2005. This credit was designed to return customers' share of the excess earnings accrued under the merger rate plan approved and implemented in 2000 governing the merger of Narragansett with Blackstone Valley Electric Company and Newport Electric Corporation.

Granite State Electric Company

The current distribution 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, the Company's 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 the Company's transmission and distribution companies are potentially responsible parties under Superfund laws for the remediation of over 180 contaminated sites in New England and New York, and for resulting damages. The Company's greatest potential Superfund liabilities relate to manufactured gas plant, or MGP, facilities formerly owned or operated by the Company's subsidiaries or their predecessors. 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. The Company is investigating or remediating these sites, or both, as appropriate.

Management believes that ongoing operations and the Company's response to the impact of the Company's 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 the Company's financial condition or results of operations because the Company recovers a majority of these costs under the Company's rate plans. The Company is pursuing claims against insurance carriers and potentially responsible parties to recover investigation and remediation costs, but management 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, 2006 and 2005, the Company has recorded an obligation of $569 million and $605 million, respectively, along with an offsetting regulatory asset, on its balance sheet. The potential high end of the range at March 31, 2006 is presently estimated at approximately $701 million.

Decommissioning Nuclear Units:
NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company (Yankee Atomic), Connecticut Yankee Atomic Power Company (Connecticut Yankee), and Maine Yankee Atomic Power Company (Maine Yankee) (together, the Yankees). These ownership interests are accounted for on the equity method. The Yankees 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, 2006			Future Estimated Billings to NEP
Nuclear Unit	% Ownership	$ (millions)	Date Retired	$ (millions)
Yankee Atomic	34.5	0.3	February 1992	47
Connecticut Yankee	19.5	9.2	December 1996	94
Maine Yankee	24.0	6.1	August 1997	54

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 United States 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 asked FERC for a rate increase to reflect increased costs for decommissioning, pensions and other employment benefits, increased security and insurance costs and other expenses. In aggregate, the increase 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) 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. On November 22, 2005, the FERC administrative law judge found that Connecticut Yankee was prudent in its administration of the decommissioning contract, its termination of Bechtel and its ongoing decommissioning of the plant. The parties have filed exceptions and are awaiting an order by FERC.

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 August 30, 2005, on the ground that it has no jurisdiction over retail rates. The Department and Bechtel requested clarification and rehearing. FERC denied their requests on October 30, 2005. The Department appealed FERC's determination in the federal court.

Connecticut Yankee and Bechtel litigated the termination of the decommissioning contract in Connecticut state court, with each party seeking substantial damages. On March 21, 2006, the parties agreed to settle the case for a payment by Bechtel to Connecticut Yankee of $15 million, and Bechtel withdrew its intervention in Connecticut Yankee's rate filing.

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, 2006 and 2005, Niagara Mohawk has a liability of $151 million and $146 million, respectively, in other non-current liabilities 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 U.S. Department of Energy (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.

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, 2006, are as follows:

(In millions of dollars)

Fiscal Year Ended March 31,		Amount
2007	$	2,319
2008		1,384
2009		1,304
2010		1,017
2011		158
Thereafter		2,741
Total	$	8,923

If the Company's subsidiaries need any additional energy to meet load requirements, they can purchase the electricity from other independent power producers (IPPs) other utilities, other energy merchants or the open market through the New York Independent System Operator (NYISO) or the 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, 2006, for the next five years, and thereafter.

(In millions of dollars)

Fiscal Year Ended March 31,		Amount
2007	$	295
2008		242
2009		5
2010		5
2011		5
Thereafter		4
Total	$	556

With respect to firm gas supply commitments, the amounts are based upon volumes specified in the contracts giving consideration to 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 currently filed tariffs. At March 31, 2006, Niagara Mohawk's firm gas supply commitments have varying expiration dates, the latest of which is March 2008. The gas storage and transportation commitments have varying expiration dates with the latest being October 2012.

Plant Expenditures:
The Company's utility plant expenditures are estimated to be approximately $711 million in fiscal 2007. At March 31, 2006, substantial commitments had been made relative to future planned expenditures. Generally construction expenditure levels are consistent from year to year, however, the Company is embarking on a Reliability Enhancement Program, to improve performance and reliability, which will result in increased capital expenditures over the next five years.

Legal Matters by Entity:

Niagara Mohawk
Station Service Cases (*Niagara Mohawk Power Corp. v. Huntley Power L.L.C. et al., FERC Docket No. EL03-27; AES Somerset, L.L.C. v. Niagara Mohawk Power Corp., FERC Docket No. EL03-204; Nine Mile Point Nuclear Station, L.L.C. v. Niagara Mohawk Power Corp., FERC Docket No. EL03-234; KeySpan-Ravenswood, Inc. v. NYISO*, FERC Docket No. EL01-50-004.) 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 Niagara Mohawk's retail charges. The FERC issued two orders on complaints filed by the 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 in January 2005 involves affiliates of NRG Energy, Inc. These orders directly conflict with Niagara Mohawk's state-approved tariffs and the orders of the PSC on station service rates. The orders, if finally upheld, will permit these generators to bypass the Niagara Mohawk's state-jurisdictional station service charges for electricity, including those set forth in the filing that was approved by the New York PSC on November 25, 2003. In the aggregate, Niagara Mohawk is owed approximately $58 million as of March 31, 2006. Niagara Mohawk appealed these orders to the U.S. Court of Appeals for the District of Columbia Circuit, and the matters were consolidated for appeal. Oral argument was heard on April 10, 2006, and on June 23, 2006, the Court issued a decision upholding the FERC's orders. Niagara Mohawk is reviewing the decision and considering whether to seek rehearing or further review.

The Court's order upholding the FERC orders has 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 the Staff and other parties may challenge Niagara Mohawk's position, in the event the FERC orders are finally upheld, Niagara Mohawk believes that the provision in the rate plan that permits Niagara Mohawk to recover lost revenues resulting from a change in law or regulation would permit it to recover the lost revenues that result from the FERC orders. These amounts are subject to regulatory review and challenge as part of the ongoing audit of Niagara Mohawk's deferral account balance in accordance with the merger rate plan.

New England Power:

Town of Norwood Dispute: From 1983 until 1998, NEP was the wholesale power supplier for the Town of Norwood (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. Through March 31, 2006, the charges assessed Norwood but not paid amount to approximately $72.2 million. NEP and Norwood are engaged in litigation and at the FERC, as follows.

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 was previously calculated under the formula which the 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 ruled that NEP correctly calculated the CTC payable by Norwood at approximately $600,000 per month from April 1998 through October 2008. FERC also reduced the late payment interest rate applicable to the unpaid CTC from 18 percent to 8 percent. In response to requests for rehearing filed by both sides, on February 22, 2006, FERC reaffirmed the validity of the CTC, and ruled that the late payment interest rate should be a simple interest rate of 18 percent. The FERC calculated the amount owed by Norwood for past and future CTC payments to be $89.1 million through December 2005. On March 14, 2006, Norwood asked FERC to reconsider the interest portion of its decision, and on March 17, moved to stay the effectiveness of the decision pending FERC's consideration of its rehearing request. On April 18, 2006, Norwood petitioned the US Court of Appeals for the First Circuit to review the FERC's orders. FERC moved on May 25 to dismiss or stay Norwood's appeal on the ground that it is premature in light of Norwood's pending request for rehearing with FERC. On June 30, FERC denied Norwood's motion for rehearing and its motion for a stay.

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 a partial payment of approximately $20 million in July 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 appealed again to the Massachusetts Appeals Court, arguing that the CTC did not bind Norwood until the FERC's July 22, 2005 order confirmed the calculation for Norwood that NEP made in 1998, and that the Appeals Court should, in any event, await final resolution of the CTC by FERC and any subsequent judicial review. On May 17, 2006, the Appeals Court denied Norwood's appeal. The court remanded the case back to the trial court to increase its January 2001 judgment consistent with the amount in FERC's February 2006 order. Norwood filed an appeal with the Massachusetts Supreme Judicial Court, and on June 28, 2006, the appeal was denied.

NOTE D – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

($'s 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, 2004	$ 3,342	$ (184,212)	$ 3,025	$ (177,845)
Other comprehensive income (loss):				
Unrealized gains on securities, net of taxes	2,858			2,858
Change in additional minimum pension liability, net of taxes		(4,629)		(4,629)
Hedging activity, net of taxes			14,557	14,557
Reclassification adjustment for gain included in net income, net of tax	(2,332)		(4,770)	(7,102)
March 31, 2005	$ 3,868	$ (188,841)	$ 12,812	$ (172,161)
Other comprehensive income (loss):				
Unrealized gains on securities, net of taxes	6,217			6,217
Change in additional minimum pension liability, net of taxes		182,489		182,489
Hedging activity, net of taxes			4,009	4,009
Reclassification adjustment for gain included in net income, net of tax	(3,236)		(21,574)	(24,810)
March 31, 2006	$ 6,849	$ (6,352)	$ (4,753)	$ (4,256)

NOTE E – DERIVATIVES AND HEDGING ACTIVITIES

In the normal course of business, the Company 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 the Company's overall Financial Risk Management Policy. At the core of the policy is a condition that the Company will engage in activities at risk only to the extent that those activities fall within commodities and financial markets to which it has a physical market exposure in terms and volumes consistent with its core business. The Company 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, 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 within the next twelve months. Other instruments are deferred in regulatory assets or liabilities according to current rate agreements and are reclassified through purchased electricity or gas expense in the hedge months. The Company'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 fiscal year 2009 (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, 2006 and 2005, Niagara Mohawk had recorded liabilities at net present value of $537 million and $619 million, respectively, for these swap contracts and had 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 they are adjusted as periodic reassessments are made of energy price forecasts.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

At March 31, 2006, Niagara Mohawk projects that it will make the following payments in connection with its swap contracts for the fiscal years 2007 through 2009 and thereafter, subject to changes in market prices and indexing provisions:

Year Ended March 31,	*(in thousands of dollars)* Projected Payment
2007	$ 246,551
2008	246,173
2009	44,729
Thereafter	-
	$ 537,453

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 No. 133. Cash flow hedges that qualify under SFAS No. 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, 2006 and the results on operations of these instruments for the year ended March 31, 2006.

	(in thousands of dollars)				
	Balances as of March 31, 2006				**Year Ended March 31, 2006**
Derivative Instrument	**Asset***	**Regulatory Deferral**	**Accumulated OCI**, net of tax**	**Accumulated Deferred Income Tax on OCI****	**Gain/(Loss) Reclass to Commodity Costs**
Qualified for Hedge Accounting					
NYMEX futures - gas supply	$ (5,358.8)	$ -	$ 4,943.0	$ (3,296.0)	$ (35,956.6)
NYMEX electric swaps - electric supply	$ 317.5	$ -	$ (190.5)	$ 127.0	$ 3,260.2
Non-qualified for Hedge Accounting					
NYMEX futures - IPP swaps/non-MRA IPP	$ (27,195.9)	$ 31,718.1	$ -	$ -	$ 59,464.9

* Differences between asset and regulatory or other comprehensive income deferral represent contracts settled for the following month.

** Other comprehensive income (OCI)

At March 31, 2005, Niagara Mohawk in part recorded a deferred gain on the futures contracts hedging the IPP swaps and non-MRA IPP of $30 million, which partially offset the consolidated balance sheet item “Derivatives and swap contracts” for $27 million, with the resulting $3 million having settled through cash for the hedge month of April 2005. For the twelve months ended March 31, 2005, settlement of NYMEX futures contracts resulted in a decrease to purchased power expense of $19 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, 2006, the realized net gain of $36 million from hedging instruments, as shown in the table above, was recorded to gas purchases and was offset by a corresponding increase in the cost of a comparable amount of gas. For the twelve months ended March 31, 2005, a realized net gain of $8 million was recorded to gas purchases and was 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 2007. There were no gains or losses recorded during the fiscal year ended March 31, 2006 from the discontinuance of gas futures or electricity swap cash flow hedges.

At March 31, 2006, the deferred gain on NYMEX electric swap contracts to hedge electricity purchases was $0.3 million. There were no open electric swaps at March 31, 2005.

USGen New England Inc. (USGen)

During the fiscal year ended March 31, 2005, NEP resumed the performance and payment obligations under power supply contracts it was required to assume in connection with USGen's bankruptcy. These contracts had been transferred to USGen in prior years as part of NEP's regulatory restructuring. NEP removed the related liability from the balance sheet and offsetting regulatory asset for the above market portion of the contracts with USGen. NEP has recorded a derivative liability of approximately $294 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 affect the results of operations, as NEP will recover the above-market cost of the contracts from customers through the CTC.

NOTE F – EMPLOYEE BENEFITS

Summary

National Grid USA companies have non-contributory defined benefit pension plans and post-retirement benefit plans (the Plans) covering substantially all employees. With the exception of New England-based union-represented employees, employees hired on or after July 15, 2002 participate under a non-contributory defined benefit 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). PBOPs 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 pension plans each year the maximum tax deductible amounts for that year (funding for VEBA plans may be based on either expense or the maximum tax deductible amounts for that year depending on the tax status of the plan). 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.

Plan Assets

The target asset allocations for the benefit plans at March 31 are:

	Pension Benefits		Non-Union PBOP		Union PBOP	
	2006	2005	**2006**	2005	**2006**	2005
U.S. equities	**42%**	43%	**33%**	37%	**51%**	50%
Global equities (including U.S.)	**6%**	7%	**0%**	0%	**0%**	0%
Non-U.S. equities	**12%**	12%	**17%**	2%	**23%**	16%
Fixed income	**35%**	35%	**50%**	61%	**26%**	34%
Private equity and property	**5%**	3%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

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

	Pension Benefits		Non-Union PBOP		Union PBOP	
	2006	2005	**2006**	2005	**2006**	2005
U.S. equities	**45%**	45%	**33%**	40%	**51%**	55%
Global equities (including U.S.)	**8%**	8%	**0%**	0%	**24%**	18%
Non-U.S. equities	**13%**	12%	**18%**	3%	**0%**	0%
Fixed income	**32%**	34%	**49%**	57%	**25%**	27%
Private equity and property	**2%**	1%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

The Company manages benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the Plans' 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. Small investments are also held in private equity with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP 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 allocation study. Investment risk and return is reviewed by the investment committee on a quarterly basis.

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 the 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

Assumptions Used for Benefits Accounting

The following weighted average assumptions were used to determine the pension and PBOP benefit obligations and net periodic benefit costs for the fiscal years ending March 31.

	Pension Benefits		PBOP	
	2006	2005	**2006**	2005
Benefit obligations				
Discount rate	**6.00%**	5.75%	**6.00%**	5.75%
Rate of compensation increase - New England	**4.30%**	4.30%	**n/a**	n/a
Rate of compensation increase - New York	**3.90%**	3.90%	**n/a**	n/a
Expected long-term rate of return	**8.00%**	8.25%	**7.80%**	7.93%
Health care cost trend rate				
Initial	**n/a**	n/a	**n/a**	10.00%
Pre 65*	**n/a**	n/a	**10.00%**	n/a
Post 65*	**n/a**	n/a	**11.00%**	n/a
Ultimate	**n/a**	n/a	**5.00%**	5.00%
Year ultimate rate is reached	**n/a**	n/a	**n/a**	2010
Pre 65*	**n/a**	n/a	**2011**	n/a
Post 65*	**n/a**	n/a	**2012**	n/a

* In fiscal year 2006, the healthcare cost trend assumption was updated to include rates for the pre 65 and post 65 groups.

	Pension Benefits			PBOP		
	2006	2005	2004	**2006**	2005	2004
Net periodic benefit cost						
Discount rate	**5.75%**	5.75%	6.25%	**5.75%**	5.75%	6.25%
Rate of compensation increase - New England	**4.30%**	4.30%	4.63%	**n/a**	n/a	n/a
Rate of compensation increase - New York	**3.90%**	3.25%	3.25%	**n/a**	n/a	n/a
Expected long-term rate of return	**8.25%**	8.50%	8.75%	**8.05%**	8.13%	8.00%
Health care cost trend rate						
Initial	**n/a**	n/a	n/a	**10.00%**	10.00%	10.00%
Ultimate	**n/a**	n/a	n/a	**5.00%**	5.00%	5.00%
Year ultimate rate reached	**n/a**	n/a	n/a	**2010**	2009	2008

The expected contributions to the Company's pension and PBOP plans during fiscal year 2007 are expected to be $164 million and $134 million, respectively.

Pension Benefits

The Company's net periodic benefit cost for the fiscal years ended March 31, 2006, 2005, and 2004 included the following components:

(in thousands)	**2006**	2005	2004
Service cost	**$ 55,412**	$ 51,346	$ 47,989
Interest cost	**155,779**	150,249	152,851
Expected return on plan assets	**(161,944)**	(165,347)	(160,892)
Amortization of unrecognized prior service cost	**4,913**	3,310	2,660
Amortization of unrecognized loss	**64,067**	54,401	44,371
Net periodic benefit costs before settlements and curtailments	**118,227**	93,959	86,979
Settlement and curtailment loss	**-**	185	23,144
Special termination benefits	**-**	-	91,855
Net periodic benefit cost	**$ 118,227**	$ 94,144	$ 201,978

The following table provides a reconciliation of the changes in the plans' fair value of assets for the fiscal years ended March 31, 2006 and 2005:

(in thousands)	**2006**	2005
Beginning balance, April 1,	**$ 1,960,624**	$ 1,947,572
Actual return on plan assets	**257,055**	134,990
Employer contributions	**134,916**	140,369
Benefit payments	**(204,985)**	(261,249)
Settlements	**-**	(1,058)
Ending balance, March 31,	**$ 2,147,610**	$ 1,960,624

The following table provides the changes in the Company's pension plans' benefit obligations, reconciliation of the benefit obligation, funded status and the amounts recognized in the balance sheet at March 31:

(in thousands)	**2006**	2005
Accumulated benefit obligation	**$ 2,470,161**	$ 2,520,588
Beginning balance, April 1,	**$ 2,808,396**	$ 2,723,921
Service cost	**55,412**	51,346
Interest cost	**155,779**	150,249
Actuarial (gains)/losses	**(66,136)**	113,983
Plan amendments	**-**	31,201
Benefit payments	**(204,985)**	(261,249)
Settlements	**-**	(1,058)
Ending balance, March 31,	**$ 2,748,466**	$ 2,808,393

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

(in thousands)	2006	2005
Funded status	**$ (600,854)**	$ (847,771)
Unrecognized prior service cost	**48,847**	53,761
Unrecognized net loss	**629,267**	854,582
Net amount recognized at March 31,	**$ 77,260**	$ 60,572

(in thousands)	2006	2005
Amounts recognized in the balance sheet consists of:		
Accrued benefit liability	**$ (410,274)**	$ (543,672)
Prepaid benefit asset	**360,183**	-
Intangible asset	**36,885**	54,888
Regulatory asset	**79,923**	252,218
Accumulated other comprehensive income	**10,543**	297,138
Net amount recognized at March 31,	**$ 77,260**	$ 60,572

The following pension benefit payments, which reflect expected future services, as appropriate, are expected to be paid from the Company's pension plans:

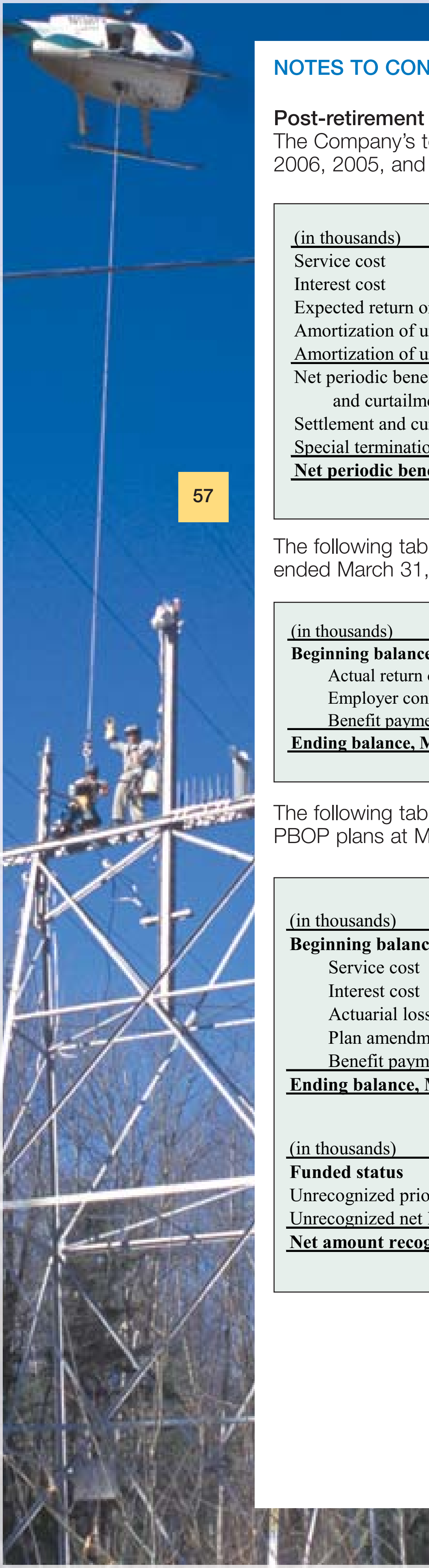
(in thousands)	**Payments**
2007	$ 197,186
2008	$ 197,260
2009	$ 198,065
2010	$ 201,831
2011	$ 207,797
2012 - 2016	$ 1,089,614

Additional Minimum Pension Liability

The Company has recorded an additional minimum pension liability of approximately $127 million and $621 million at March 31, 2006 and 2005, respectively. While the offset to this entry would normally be a charge to other comprehensive income, certain Company subsidiaries, have recorded regulatory assets in the amount of $80 million and $252 million at March 31, 2006 and 2005, respectively, because they fully recover all pension costs.

Defined Contribution Plan

The Company also has several defined contribution pension plans primarily (section 401(k) employee savings fund plans) that cover substantially all employees. Employer matching contributions of approximately $11 million, $10 million, and $12 million were expensed in fiscal year 2006, 2005, and 2004, respectively.



Post-retirement Benefits Other than Pensions

The Company's total net periodic benefit cost of PBOPs for the fiscal years ended March 31, 2006, 2005, and 2004 included the following components:

(in thousands)	**2006**	2005	2004
Service cost	**$ 28,293**	$ 22,200	$ 17,930
Interest cost	**112,407**	103,810	98,849
Expected return on plan assets	**(73,782)**	(73,880)	(60,957)
Amortization of unrecognized prior service cost	**13,330**	4,678	(687)
Amortization of unrecognized loss	**45,648**	36,756	36,531
Net periodic benefit costs before settlements and curtailments	**125,896**	93,564	91,666
Settlement and curtailment loss	**-**	-	16,066
Special termination benefits	**-**	-	8,936
Net periodic benefit cost	**$ 125,896**	$ 93,564	$ 116,668

The following table provides a reconciliation of the PBOP fair value of assets for the fiscal years ended March 31, 2006 and 2005.

(in thousands)	**2006**	2005
Beginning balance, April 1,	**$ 922,173**	$ 907,995
Actual return on plan assets	**113,920**	49,373
Employer contributions	**53,700**	59,715
Benefit payments	**(101,604)**	(94,910)
Ending balance, March 31,	**$ 988,189**	$ 922,173

The following tables provide the reconciliation of the benefit obligation and the funded status of the PBOP plans at March 31:

(in thousands)	**2006**	2005
Beginning balance, April 1,	**$ 2,019,009**	$ 1,834,258
Service cost	**28,293**	22,200
Interest cost	**112,407**	103,810
Actuarial losses	**71,103**	9,435
Plan amendments	**-**	146,689
Benefit payments	**(106,045)**	(97,383)
Ending balance, March 31,	**$ 2,124,767**	$ 2,019,009

(in thousands)	**2006**	2005
Funded status	**$ (1,136,579)**	$ (1,096,837)
Unrecognized prior service cost	**119,775**	133,106
Unrecognized net loss	**583,074**	597,757
Net amount recognized at March 31,	**$ (433,730)**	$ (365,974)

As a result of the Medicare Act of 2003, the Company receives a federal subsidy for sponsoring a retiree healthcare plan that provides a benefit that is actuarially equivalent to Medicare Part D. The following PBOP benefit payments and subsidies, which reflect expected future service, as appropriate, are expected to be paid and received:

(in thousands)	Payments	Subsidies
2007	$ 114,283	$ 7,347
2008	$ 119,666	$ 7,980
2009	$ 123,471	$ 8,587
2010	$ 127,807	$ 9,038
2011	$ 131,602	$ 9,347
2012 - 2016	$ 657,237	$ 50,175

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

	2006	2005
Increase 1%		
Total of service cost plus interest cost	**$ 25,944**	$ 21,637
Postretirement benefit obligation	**$ 313,376**	$ 295,000
Decrease 1%		
Total of service cost plus interest cost	**$ (21,558)**	$ (18,196)
Postretirement benefit obligation	**$ (280,250)**	$ (257,030)

Settlement Losses

Under SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits", 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 approximately $22 million in fiscal year 2004 relating to the re-measurement of the benefit plans from the voluntary early retirement offer.

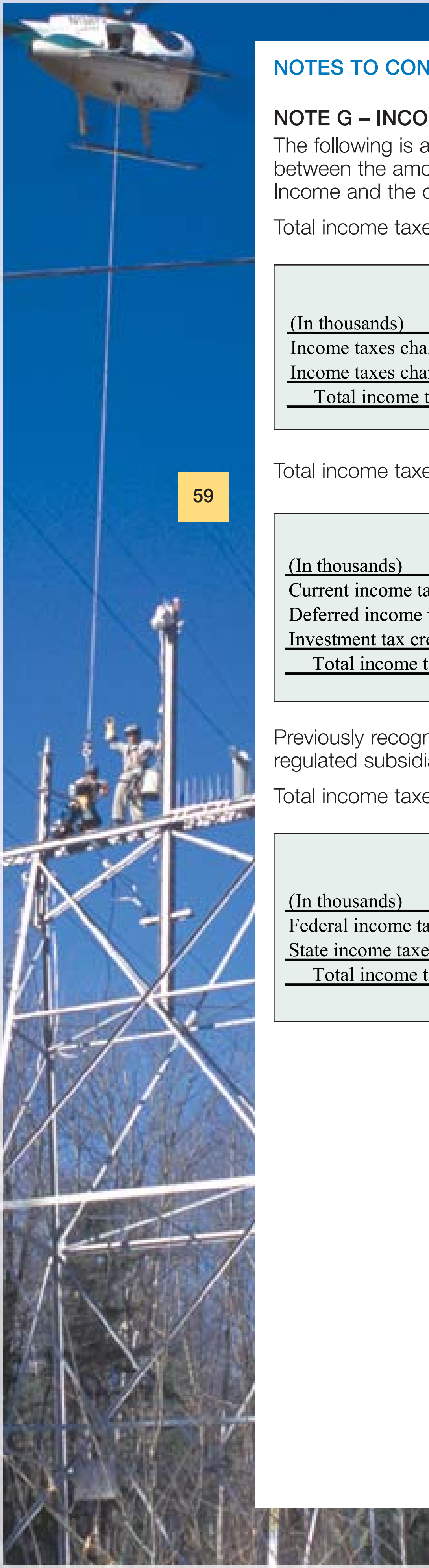
In July 2004, Niagara Mohawk obtained PSC approval that would provide rate recovery for approximately $14 million of the $30 million pension settlement loss incurred in fiscal 2003. In addition, the agreement covers the funding of the entire settlement loss to benefit plan trust funds. Niagara Mohawk has filed a petition with the PSC seeking recovery of a $22 million pension settlement loss incurred in fiscal year 2004.

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 post-retirement benefit plans" includes certain other components. First, Niagara Mohawk is required under the Merger Rate Plan to defer the difference between pension and post-retirement 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 post-retirement 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 2006 and 2005 was approximately $4 million and $7 million, respectively. The phase-in deferral is being amortized at a rate of approximately $3 million per year.

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.



NOTE G – INCOME TAXES

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

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

(In thousands)	For the Year Ended March 31, **2006**	2005	2004
Income taxes charged to operations	**$ 316,052**	$ 306,229	$ 269,667
Income taxes charged (credited) to "Other income"	**3,816**	(4,263)	1,534
Total income taxes	**$ 319,868**	$ 301,966	$ 271,201

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

(In thousands)	For the Year Ended March 31, **2006**	2005	2004
Current income taxes	**$ 281,995**	$ 88,011	$ 127,597
Deferred income taxes	**44,612**	220,121	150,422
Investment tax credits, net	**(6,739)**	(6,166)	(6,818)
Total income taxes	**$ 319,868**	$ 301,966	$ 271,201

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

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

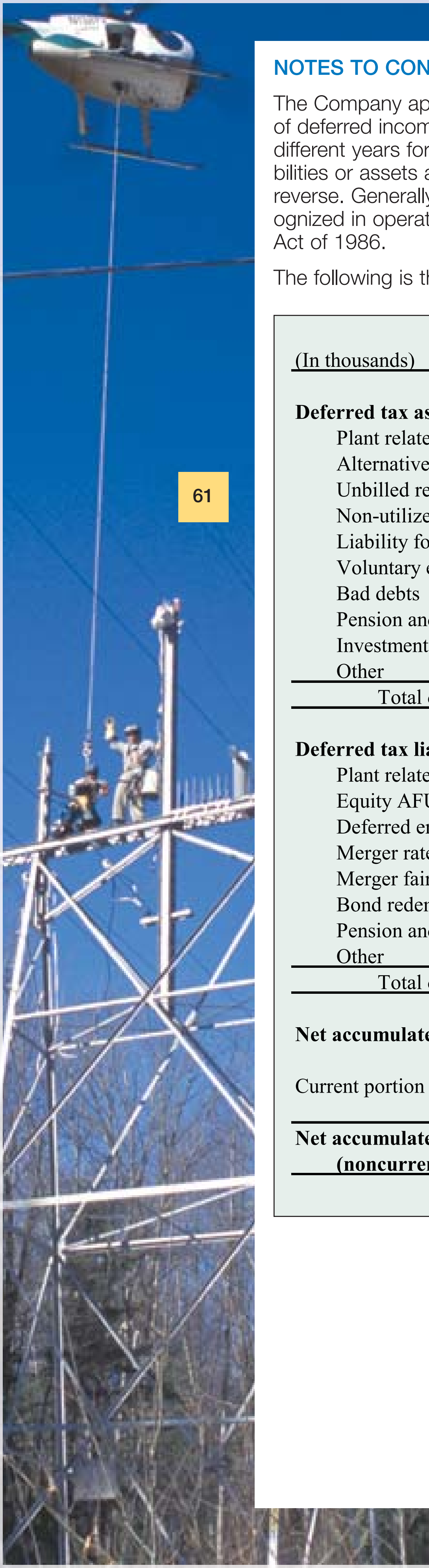
(In thousands)	For the Year Ended March 31, **2006**	2005	2004
Federal income taxes	**$ 272,505**	$ 273,269	$ 235,775
State income taxes	**47,363**	28,697	35,426
Total income taxes	**$ 319,868**	$ 301,966	$ 271,201

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

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:

	For the Year ended March 31,		
(In thousands)	**2006**	2005	2004
Computed tax at statutory rate	**$ 309,087**	$ 299,483	$ 185,853
Increases (reductions) in tax resulting from:			
Amortization of ITC, net	**(6,739)**	(6,013)	(6,616)
State income tax, net of federal income tax benefit	**30,200**	28,894	23,027
Tax return true-ups	**(17,154)**	(26,308)	20,232
Foreign tax credits unutilized	**-**	-	32,350
Rate recovery of deficiency in deferred tax reserves	**11,159**	1,856	2,455
Book/tax depreciation not normalized	**10,156**	16,852	21,328
Unamortized debt discount not normalized	**3,298**	487	(1,556)
Cost of removal	**(7,298)**	(5,664)	(6,857)
Medicare act	**(11,385)**	(5,907)	-
All other differences	**(1,456)**	(1,714)	985
Total income taxes	**$ 319,868**	$ 301,966	$ 271,201



NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

The Company applies SFAS No. 109, "Accounting for Income Taxes," which requires recognition of deferred income taxes using the liability method for temporary differences that are reported in different years for financial reporting and tax purposes. 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.

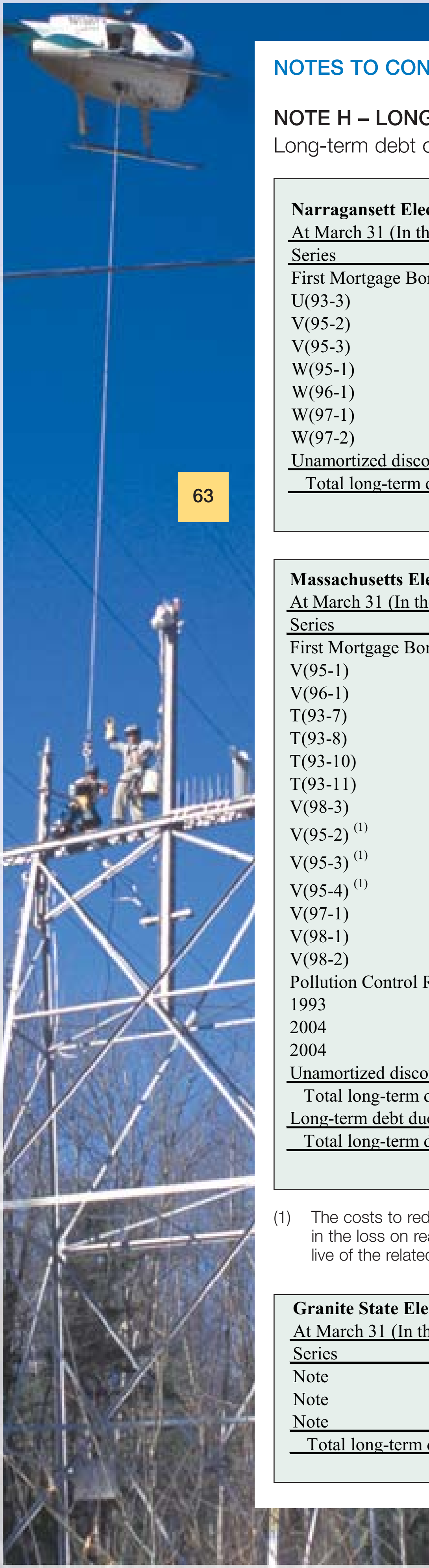
The following is the detail of the Company's accumulated deferred income taxes:

	At March 31,	
(In thousands)	**2006**	2005
Deferred tax assets:		
Plant related	**$ 112,757**	$ 110,725
Alternative minimum tax	**119,294**	111,609
Unbilled revenues	**17,070**	54,030
Non-utilized NOL carryforward	**-**	105,023
Liability for environmental costs	**191,307**	229,723
Voluntary early retirement program	**42,089**	41,558
Bad debts	**62,210**	62,046
Pension and other post-retirement benefits	**248,446**	185,324
Investment tax credit	**10,560**	12,146
Other	**416,477**	276,520
Total deferred tax assets	**1,220,210**	1,188,704
Deferred tax liabilities:		
Plant related	**(1,429,641)**	(1,358,129)
Equity AFUDC	**(63,668)**	(62,468)
Deferred environmental restoration costs	**(186,842)**	(200,175)
Merger rate plan stranded costs	**(795,184)**	(848,182)
Merger fair value pension and OPEB adjustment	**(109,478)**	(128,188)
Bond redemption and debt discount	**(30,009)**	(29,233)
Pension and other post-retirement benefits	**(61,784)**	(141,422)
Other	**(569,349)**	(284,903)
Total deferred tax liabilities	**(3,245,955)**	(3,052,700)
Net accumulated deferred income tax liability	**(2,025,745)**	(1,863,996)
Current portion (net deferred tax asset)	**197,209**	340,837
Net accumulated deferred income tax liability (noncurrent)	**$ (2,222,954)**	$ (2,204,833)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

The Company and other related subsidiaries participate with National Grid Holdings, Inc. (NGHI), a wholly owned subsidiary of National Grid plc, in filing consolidated US federal income tax returns. The Company's tax provisions and tax accounts are calculated on a separate company basis. Federal income tax returns have been examined and all appeals and issues have been agreed upon by the Internal Revenue Service (IRS) and the NGHI consolidated filing group through March 22, 2000, the date of the group's acquisition by National Grid plc. The IRS is currently reviewing the March 31, 2001 and March 31, 2002 tax returns of the NGHI consolidated filing group. The IRS has issued a preliminary notice of deficiency disallowing certain tax deductions taken in these consolidated US federal income tax returns. These adjustments are being appealed. The Company has joint and several liability for any potential assessments against the consolidated group. Management believes that the positions taken by the Company and its related subsidiaries and parent company are appropriate and the resolution of the tax matters will not have a material effect on the Company's financial position, results of operations or cash flows.

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 NGHI. The consolidated tax filing group was able to utilize the remaining NOL carryforward prior to its expiration in 2019. The amount of the NOL carryforward as of March 31, 2006 and 2005 was $0 and $301 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, 2006 or 2005.



NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

NOTE H – LONG-TERM DEBT

Long-term debt consists of the following:

Narragansett Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2006	2005
First Mortgage Bonds:				
U(93-3)	6.650	June 30, 2008	**$ 5,000**	$ 5,000
V(95-2)	7.750	June 2, 2025	**-**	10,000
V(95-3)	7.500	October 10, 2025	**-**	7,000
W(95-1)	7.300	November 13, 2025	**-**	16,000
W(96-1)	7.240	January 19, 2026	**-**	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
Unamortized discounts			**(237)**	(263)
Total long-term debt			**$ 14,763**	$ 49,737

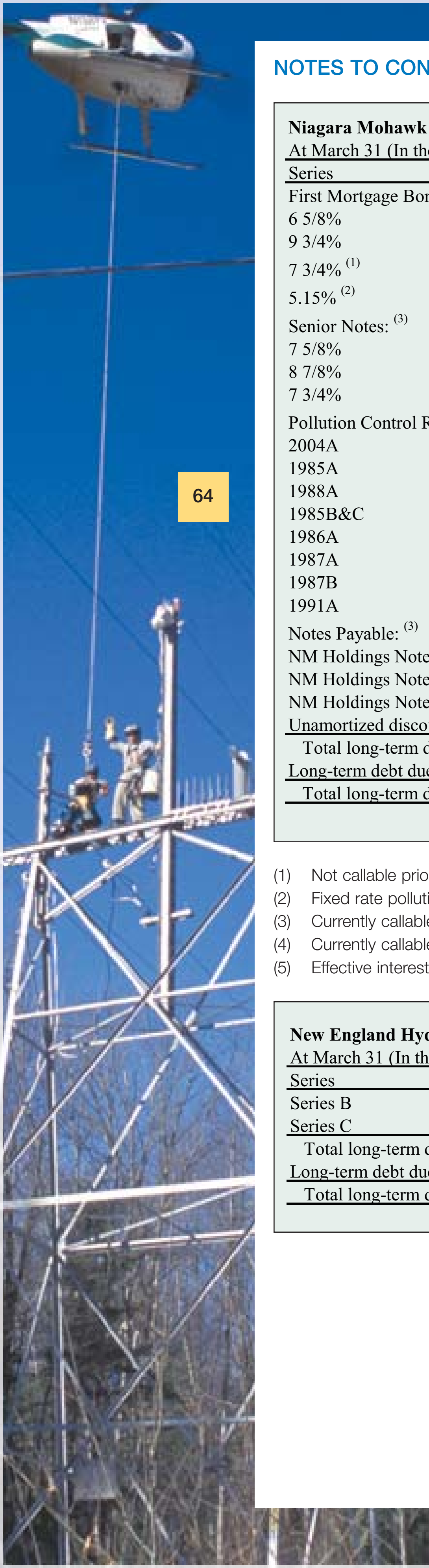
Massachusetts Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2006	2005
First Mortgage Bonds:				
V(95-1)	6.720	June 23, 2005	**$ -**	$ 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
V(95-2) (1)	7.630	June 27, 2025	**-**	10,000
V(95-3) (1)	7.600	September 12, 2025	**-**	10,000
V(95-4) (1)	7.630	September 12, 2025	**-**	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
2004	Variable	August 1, 2008	**20,000**	-
2004	Variable	August 1, 2014	**20,000**	-
Unamortized discounts			**(587)**	(689)
Total long-term debt			**154,413**	194,311
Long-term debt due within one year			**20,000**	10,000
Total long-term debt, excluding current portion			**$ 134,413**	$ 184,311

(1) The costs to redeem the long-term debt prior to maturity were approximately $1.1 million. This amount was recorded in the loss on reacquired debt regulatory asset account and is being amortized ratably as interest expense over the live of the related issuance.

Granite State Electric
At March 31 (In thousands)

Series	Rate %	Maturity	2006	2005
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
Total long-term debt			**$ 15,000**	$ 15,000



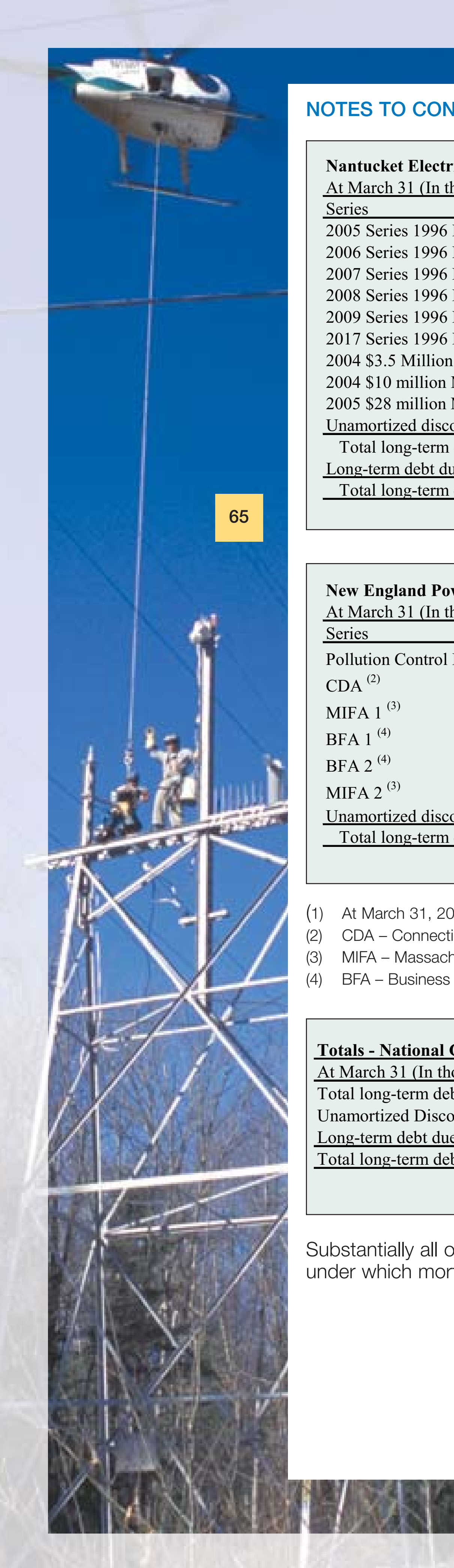
Niagara Mohawk
At March 31 (In thousands)

Series	Rate %	Maturity	2006	2005
First Mortgage Bonds:				
6 5/8%	6.625	July 1, 2005	$ -	$ 110,000
9 3/4%	9.750	November 1, 2005	-	137,981
7 3/4% [1]	7.750	May 15, 2006	**275,000**	275,000
5.15% [2]	5.150	November 1, 2025	**75,000**	75,000
Senior Notes: [3]				
7 5/8%	7.625	October 1, 2005	-	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
Pollution Control Revenue Bonds - Variable Rate: [4]				
2004A	Variable	October 1, 2013	**45,600**	45,600
1985A	Variable	July 1, 2015	**100,000**	100,000
1988A	Variable	December 1, 2023	**69,800**	69,800
1985B&C	Variable	December 1, 2025	**75,000**	75,000
1986A	Variable	December 1, 2026	**50,000**	50,000
1987A	Variable	March 1, 2027	**25,760**	25,760
1987B	Variable	July 1, 2027	**93,200**	93,200
1991A	Variable	July 1, 2029	**115,705**	115,705
Notes Payable: [3]				
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
Unamortized discounts			**(1,133)**	(1,496)
Total long-term debt			**2,923,932**	3,473,989
Long-term debt due within one year			**275,000**	550,420
Total long-term debt, excluding current portion			**$ 2,648,932**	$ 2,923,569

(1) Not callable prior to maturity.
(2) Fixed rate pollution control revenue bonds first callable November 1, 2008 at 102%.
(3) Currently callable with make-whole provisions.
(4) Currently callable at par.
(5) Effective interest rate at March 31, 2006 and March 31, 2005 was 3.24% and 2.33%, respectively.

New England Hydro Finance
At March 31 (In thousands)

Series	Rate %	Maturity	2006	2005
Series B	9.260	April 17, 2007	**$ 6,350**	$ 12,110
Series C	9.410	October 17, 2015	**46,270**	46,270
Total long-term debt			**52,620**	58,380
Long-term debt due within one year			**5,760**	5,760
Total long-term debt, excluding current portion			**$ 46,860**	$ 52,620



NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(continued)*

Nantucket Electric
At March 31 (In thousands)

Series	Rate %	Maturity	**2006**	2005
2005 Series 1996 MIFA Tax Exempt	6.750	July 1, 2005	**$ -**	$ 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
2017 Series 1996 MIFA Tax Exempt	5.875	July 1, 2017	**10,500**	20,500
2004 $3.5 Million MIFA Tax-Exempt	Variable	March 16, 2016	**2,495**	2,640
2004 $10 million MIFA Tax-Exempt	Variable	March 1, 2039	**10,000**	-
2005 $28 million MIFA Tax-Exempt	Variable	December 1, 2040	**28,000**	-
Unamortized discounts			**(72)**	(78)
Total long-term debt			**56,523**	30,062
Long-term debt due within one year			**1,560**	1,545
Total long-term debt, excluding excluding current portion			**$ 54,963**	$ 28,517

New England Power
At March 31 (In thousands)

Series	Rate %	Maturity	**2006**	2005
Pollution Control Revenue Bonds: (1)				
CDA (2)	Variable	October 15, 2015	**$ 38,500**	$ 38,500
MIFA 1 (3)	Variable	March 1, 2018	**79,250**	79,250
BFA 1 (4)	Variable	November 1, 2020	**135,850**	135,850
BFA 2 (4)	Variable	November 1, 2020	**50,600**	50,600
MIFA 2 (3)	Variable	October 1, 2022	**106,150**	106,150
Unamortized discounts			**(40)**	(46)
Total long-term debt			**$ 410,310**	$ 410,304

(1) At March 31, 2006, interest rates on NEP's variable rate bonds ranged from 3.17 percent to 3.36 percent.
(2) CDA – Connecticut Development Authority
(3) MIFA – Massachusetts Industrial Finance Authority (now known as Massachusetts Development Finance Agency)
(4) BFA – Business Finance Authority of the State of New Hampshire

Totals - National Grid USA

At March 31 (In thousands)	**2006**	2005
Total long-term debt	**$ 3,629,630**	$ 4,234,355
Unamortized Discount on Debt	**(2,069)**	(2,572)
Long-term debt due within one year	**302,320**	567,725
Total long-term debt, excluding current portion	**$ 3,325,241**	$ 3,664,058

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, 2006, the aggregate payments to retire maturing long term debt are as follows (in thousands):

Fiscal Year	Amount
2007	$ 302,320
2008	207,225
2009	687,115
2010	357,130
2011	357,150
Thereafter	1,718,690
	$ 3,629,630

At March 31, 2006, the Company's subsidiaries' long term debt, excluding intercompany debt, had a carrying value of $2.4 billion and a fair value of $2.5 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 I – SHORT-TERM DEBT

NEP

At March 31, 2006 and 2005, NEP had lines of credit and standby bond purchase facilities with banks totaling $440 million, 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. There were no borrowings under these lines of credit at March 31, 2006.

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 plc, and certain other subsidiaries of National Grid plc, including for the purpose of funding the money pool, if necessary. At March 31, 2006 and 2005, the Company had borrowed $576 million and $619 million, respectively, under this arrangement.

NOTE J – CUMULATIVE PREFERRED STOCK

A summary of cumulative preferred stock at March 31, 2006 and 2005 is as follows (in thousands except for share data and call price):

	Company	Shares Outstanding		Amount (in 000's)		Call Price
		March 31, 2006	March 31, 2005	**March 31, 2006**	March 31, 2005	
$100 par value -						
3.40% Series	Niagara Mohawk	**57,536**	57,536	**$ 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**	9,496	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**	3,410	102.000
6.00% Series	New England Power	**11,117**	11,117	**1,112**	1,112	(a)
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**2,454**	2,454	55.000
4.64% Series	Narragansett	**57,057**	57,057	**2,854**	2,854	52.125
Total		**576,243**	576,243	**$ 52,317**	$ 52,317	

(a) Noncallable.

NOTE K – COST OF REMOVAL AND ASSET RETIREMENT OBLIGATION

In 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company was required to adopt SFAS No. 143 as of April 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 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 SFAS No. 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 SFAS No. 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., it is 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 cost of removal collections from customers has historically been embedded within accumulated deprecation (as these costs have been charged over time through deprecation expense). With the adoption of SFAS No. 143 the Company has reclassified these 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 $538 million and $505 million for cost of removal through March 31, 2006 and March 31, 2005, respectively.

In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations," that clarifies that the term 'conditional asset retirement obligation' used in SFAS No.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 event that may or may not be within the control of the Company. This statement is effective for the Company for its fiscal year ended March 31, 2006. The Company has a $13 million asset retirement obligation reserve as of March 31, 2006 which does not have a material impact on the Company's results of operation or financial position.