Interest Charges, Net: Interest charges, net increased $20 million in 2006. The increase is primarily due to:

- Higher carrying costs on regulatory liabilities, and
- Higher rates on short-term and variable rate debt.

Interest charges, net increased $12 million in 2005. The increase is primarily due to:

- A net increase of $137 million in the aggregate amount of long-term debt, and
- An increase in rates on variable rate debt and notes payable.

Income Taxes on Continuing Operations: The effective tax rate for continuing operations was 37% in 2006, 40% in 2005 and 51% in 2004.

The decrease in the 2006 effective tax rate for continuing operations was primarily due to variances in recurring flow-through items, differences in the 2005 filed tax return compared to the 2005 book tax expense and settlement of an audit of our 2002 and 2003 federal income tax returns.

The 2005 effective tax rate was essentially at the combined federal and state statutory rate and declined primarily due to the effect of the regulatory treatment of RG&E's deferred gain on the sale of Ginna in 2004.

Pension Income: Periodic pension income is included in other operating and maintenance expenses and reduces the amount of expense that would otherwise be reported. Pension income for 2006 was the same as in 2005 and $1 million higher than in 2004.

	2006	**2005**	**2004**
($ in Millions)			
Periodic pension income (pretax)	**$30**	$30	$29
As a percent of net income	**7%**	7%	8%

The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. We expect pension income to decline in future years as prior year gains are fully amortized.

We estimate pension income of $43 million for 2007 and expect to contribute between $10 million and $20 million to our pension plans in 2007. (See Item 8 - Note 14 to our

Consolidated Financial Statements.)

Energy East Corporation
Consolidated Balance Sheets

December 31,	2006	2005
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$93,373**	$120,009
Investments available for sale	**20,000**	192,925
Accounts receivable and unbilled revenues, net	**914,657**	933,680
Fuel and natural gas in storage, at average cost	**277,766**	278,590
Materials and supplies, at average cost	**33,273**	33,886
Deferred income taxes	**93,187**	-
Derivative assets	**1,327**	278,855
Prepayments and other current assets	**193,226**	92,613
Total Current Assets	**1,626,809**	1,930,558
Utility Plant, at Original Cost		
Electric	**5,557,858**	5,403,134
Natural gas	**2,654,426**	2,574,574
Common	**550,440**	450,641
	8,762,724	8,428,349
Less accumulated depreciation	**2,935,798**	2,764,399
Net Utility Plant in Service	**5,826,926**	5,663,950
Construction work in progress	**121,097**	119,504
Total Utility Plant	**5,948,023**	5,783,454
Other Property and Investments	**183,315**	203,159
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**263,659**	309,888
Deferred income taxes	**-**	13,482
Unfunded future income taxes	**256,683**	117,241
Environmental remediation costs	**128,925**	135,376
Unamortized loss on debt reacquisitions	**52,724**	60,933
Nonutility generator termination agreements	**79,241**	86,890
Natural gas hedges	**47,372**	-
Pension and other postretirement benefits	**351,011**	-
Other	**356,299**	384,173
Total regulatory assets	**1,535,914**	1,107,983
Other assets		
Goodwill	**1,526,048**	1,525,353
Prepaid pension benefits	**577,356**	741,831
Derivative assets	**46,375**	69,156
Other	**118,561**	126,214
Total other assets	**2,268,340**	2,462,554
Total Regulatory and Other Assets	**3,804,254**	3,570,537
Total Assets	**$11,562,401**	$11,487,708

The notes on pages 61 through 93 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31,	2006	2005
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$260,768**	$326,527
Notes payable	**109,363**	121,347
Accounts payable and accrued liabilities	**470,325**	629,158
Interest accrued	**57,243**	46,522
Taxes accrued	**44,009**	-
Deferred income taxes	**-**	80,984
Unfunded future income tax	**19,664**	-
Derivative liabilities	**71,678**	2,019
Customer refund	**70,770**	14,698
Other	**209,839**	171,754
Total Current Liabilities	**1,313,659**	1,393,009
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	**843,273**	797,544
Deferred income taxes	**105,528**	-
Gain on sale of generation assets	**127,674**	173,216
Pension benefits	**127,330**	22,798
Natural gas hedges	**-**	49,205
Other	**93,268**	124,251
Total regulatory liabilities	**1,297,073**	1,167,014
Other liabilities		
Deferred income taxes	**1,105,117**	1,033,287
Nuclear plant obligations	**202,963**	234,907
Pension and other postretirement benefits	**530,838**	428,691
Environmental remediation costs	**168,949**	166,462
Derivative liability	**21,871**	24,887
Other	**306,283**	475,081
Total other liabilities	**2,336,021**	2,363,315
Total Regulatory and Other Liabilities	**3,633,094**	3,530,329
Debt owed to subsidiary holding solely parent debentures	**-**	355,670
Other long-term debt	**3,726,709**	3,311,395
Total long-term debt	**3,726,709**	3,667,065
Total Liabilities	**8,673,462**	8,590,403
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable solely at the option of subsidiaries	**24,592**	24,631
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 147,907 shares outstanding at December 31, 2006, and 147,701 shares outstanding at December 31, 2005)	**1,480**	1,478
Capital in excess of par value	**1,505,795**	1,489,256
Retained earnings	**1,382,461**	1,294,580
Accumulated other comprehensive income (loss)	**(23,779)**	89,085
Treasury stock, at cost (52 shares at December 31, 2006, and 53 shares at December 31, 2005)	**(1,610)**	(1,725)

Total Common Stock Equity	**2,864,347**	2,872,674
Total Liabilities and Stockholders' Equity	**$11,562,401**	$11,487,708

The notes on pages 61 through 93 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Income

Year Ended December 31,	**2006**	**2005**	**2004**
(Thousands, except per share amounts)			
Operating Revenues			
Utility	**$4,720,638**	$4,753,105	$4,330,472
Other	**510,027**	545,438	426,220
Total Operating Revenues	**5,230,665**	5,298,543	4,756,692
Operating Expenses			
Electricity purchased and fuel used in generation			
Utility	**1,467,068**	1,457,746	1,321,081
Other	**353,402**	360,621	249,330
Natural gas purchased			
Utility	**1,079,980**	1,161,059	952,806
Other	**79,472**	107,755	77,508
Other operating expenses	**796,350**	797,015	799,460
Maintenance	**218,499**	197,704	173,191
Depreciation and amortization	**282,568**	277,217	292,457
Other taxes	**249,834**	246,271	252,860
Gain on sale of generation assets	-	-	(340,739)
Deferral of asset sale gain	-	-	228,785
Total Operating Expenses	**4,527,173**	4,605,388	4,006,739
Operating Income	**703,492**	693,155	749,953
Other (Income)	**(46,126)**	(32,904)	(35,497)
Other Deductions	**24,578**	8,858	15,803
Interest Charges, Net	**308,824**	288,897	276,890
Preferred Stock Dividends of Subsidiaries	**1,129**	1,474	3,691
Income From Continuing Operations Before Income Taxes	**415,087**	426,830	489,066
Income Taxes	**155,255**	169,997	251,445
Income From Continuing Operations	**259,832**	256,833	237,621
Discontinued Operations			
Loss from discontinued operations (including loss on disposal of $(7,565) in 2004)	-	-	(7,109)
Income taxes	-	-	1,175
Loss From Discontinued Operations	-	-	(8,284)
Net Income	**$259,832**	$256,833	$229,337
Earnings per Share From Continuing Operations, basic	**$1.77**	$1.75	$1.63
Earnings per Share From Continuing Operations, diluted	**$1.76**	$1.74	$1.62
Loss per Share From Discontinued Operations, basic and diluted	-	-	$(.06)
Earnings per Share, basic	**$1.77**	$1.75	$1.57
Earnings per Share, diluted	**$1.76**	$1.74	$1.56
Average Common Shares Outstanding, basic	**146,962**	146,964	146,305

Average Common Shares Outstanding, diluted	147,717	147,474	146,713

The notes on pages 61 through 93 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Cash Flows

Year Ended December 31,	2006	2005	2004
(Thousands)			
Operating Activities			
Net income	**$259,832**	$256,833	$229,337
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	**418,152**	382,873	377,181
Income taxes and investment tax credits deferred, net	**31,125**	69,729	83,327
Income taxes related to gain on sale of generation assets	**-**	-	111,954
Gain on sale of generation assets	**-**	-	(340,739)
Deferral of asset sale gain	**-**	-	228,785
Pension income	**(30,081)**	(29,967)	(28,808)
Changes in current operating assets and liabilities			
Accounts receivable and unbilled revenues, net	**16,026**	(107,308)	(70,067)
Inventory	**1,437**	(86,735)	(43,579)
Prepayments and other current assets	**(65,466)**	(36,373)	1,326
Accounts payable and accrued liabilities	**(140,521)**	198,932	91,527
Taxes accrued	**11,148**	1,376	(91,840)
Interest accrued	**10,721**	3,053	(5,520)
Customer refund	**(15,485)**	(25,329)	(58,219)
Other current liabilities	**(15,767)**	11,448	(37,213)
Pension contributions	**(400)**	(54,320)	(19,661)
Changes in other assets			
RG&E nuclear plant dispute settlement	**(33,655)**	(125)	(141)
Other	**(1,722)**	(76,167)	(82,733)
Changes in other liabilities			
RG&E generation related ASGA charges	**(55,420)**	(25,798)	(31,064)
Other	**(10,430)**	18,150	25,247
Net Cash Provided by Operating Activities	**379,494**	500,272	339,100
Investing Activities			
Sale of generation assets	**-**	-	453,678
Excess decommissioning funds retained	**-**	-	76,593
Utility plant additions	**(408,231)**	(331,294)	(299,263)
Other property additions	**(3,817)**	(2,507)	(5,623)
Other property sold	**342**	25,704	6,161
Maturities of current investments available for sale	**1,054,665**	1,635,005	994,680
Purchases of current investments available for sale	**(881,740)**	(1,692,275)	(1,130,335)
Investments	**11,022**	(3,064)	1,062
Net Cash (Used in) Provided by Investing Activities	**(227,759)**	(368,431)	96,953
Financing Activities			
Issuance of common stock	**343**	2,654	3,083
Repurchase of common stock	**(6,107)**	(6,492)	(6,071)
Issuance of first mortgage bonds	**-**	70,000	-
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	**(39)**	(47,260)	(201,005)
Derivative activity	**22,899**	-	-
Long-term note issuances	**652,137**	208,893	212,975
Long-term note repayments	**(667,263)**	(120,061)	(249,025)
Notes payable three months or less, net	**(12,873)**	(85,967)	(92,932)
Notes payable issuances	**1,436**	1,251	4,000
Notes payable repayments	**(547)**	(408)	(13,000)
Book overdraft	**(1,008)**	4,460	5,892
Dividends on common stock	**(167,349)**	(150,367)	(136,374)

Net Cash Used in Financing Activities	**(178,371)**	(123,297)	(472,457)
Net Increase (Decrease) in Cash and Cash Equivalents	**(26,636)**	8,544	(36,404)
Cash and Cash Equivalents, Beginning of Year	**120,009**	111,465	147,869
Cash and Cash Equivalents, End of Year	**$93,373**	$120,009	$111,465

The notes on pages 61 through 93 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	**Common Stock Outstanding $.01 Par Value Shares**	**Amount**	**Capital in Excess of Par Value**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**
Balance, January 1, 2004	146,262	$1,463	$1,456,220	$1,126,457	$(11,214)
Net income				229,337	
Other comprehensive income, net of tax					(32,347)
Comprehensive income					
Common stock dividends declared ($1.055 per share)				(154,261)	
Common stock issued - Investor Services Program	872	9	20,962		
Common stock repurchased	(250)				
Common stock issued - restricted stock plan	242		(132)		
Amortization of deferred compensation under restricted stock plan					
Treasury stock transactions, net	(8)		94		
Amortization of capital stock issue expense, net			374		
Balance, December 31, 2004	147,118	1,472	1,477,518	1,201,533	(43,561)
Net income				256,833	
Other comprehensive income, net of tax					132,646
Comprehensive income					
Common stock dividends declared ($1.115 per share)				(163,786)	
Common stock issued - Investor Services Program	607	6	16,066		
Common stock repurchased	(250)				
Common stock issued - restricted stock plan	265		(6,404)		
Amortization of deferred compensation under restricted stock plan					
Treasury stock transactions, net	(39)		1,702		
Amortization of capital stock issue expense, net			374		
Balance, December 31, 2005	147,701	1,478	1,489,256	1,294,580	89,085
Net income				259,832	
Other comprehensive income, net of tax					(113,502)
Comprehensive income					
Adjustment to initially apply Statement 158					638
Common stock dividends declared ($1.17 per share)				(171,951)	
Common stock issued - Investor Services Program	204	2	4,943		
Common stock repurchased	(250)				
Common stock issued - restricted stock plan	274		(6,722)		
Amortization of restricted stock plan grants			8,458		
Treasury stock transactions, net	(22)		(2)		
Amortization of capital stock issue expense, net			9,862		

Balance, December 31, 2006	147,907	$1,480	$1,505,795	$1,382,461	$(23,779)

The notes on pages 61 through 93 are an integral part of our consolidated financial statements..

Notes to Consolidated Financial Statements

Energy East Corporation

Note 1. Significant Accounting Policies

Background: Energy East is a public utility holding company under the Public Utility Holding Company Act of 2005. We are a super-regional energy services and delivery company with operations in New York, Connecticut, Massachusetts, Maine and New Hampshire. Our wholly-owned subsidiaries, and their principal operating utilities, include: Berkshire Energy - Berkshire Gas; CMP Group - CMP; CNE - SCG; CTG Resources - CNG; and RGS Energy - NYSEG and RG&E.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $221 million for 2006 and $315 million for 2005, and are shown net of an allowance for doubtful accounts at December 31 of $59 for 2006 and $53 million for 2005. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $81 million in 2006, $66 million in 2005 and $45 million in 2004.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region and operating segment and other economic data. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors such as economic conditions and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

***Asset retirement obligation and FIN 47*:** In accordance with FASB Statement 143 and FIN 47, we record the fair value of the liability for an asset retirement obligation and/or a conditional asset retirement obligation in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically over time, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our rate-regulated entities defer any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

FIN 47 clarifies that the term conditional asset retirement obligation as used in Statement 143 refers to an entity's 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. FIN 47 requires that if an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional asset retirement obligation, it must recognize that liability at the time the liability is incurred. We began applying FIN 47 effective December 31, 2005. Our application of FIN 47 did not have a material effect on our financial position, and there was no effect on our results of operations or cash flows.

Notes to Consolidated Financial Statements

Energy East Corporation

Our asset retirement obligation (ARO) including our estimated conditional asset retirement obligation at December 31 was $57 million for 2006 and $30 million for 2005. The ARO primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl (PCB) contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with our AROs are generation property, gas storage property, distribution property and other property. Our pro forma conditional asset retirement obligation was $27 million at December 31, 2004.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2006 and 2005. The increase for 2006 is primarily for removal of asbestos from generating stations and the increase for 2005 is primarily for initially applying FIN 47.

Year ended December 31,	**2006**	**2005**
(Thousands)		
ARO, beginning of year	**$29,895**	$2,378
Liabilities incurred during the year	**21,025**	27,958
Liabilities settled during the year	**(1,435)**	(579)
Accretion expense	**1,538**	138
Revisions in estimated cash flows	**6,230**	-
ARO, end of year	**$57,253**	$29,895

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydro dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Statement 143 provides that if the requirements of Statement 71 are met, a regulatory liability should be recognized, for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Basic and diluted earnings per share: We determine basic EPS by dividing net income by the weighted-average number of shares of common stock outstanding during the period. The weighted-average common shares outstanding for diluted EPS include the incremental effect of restricted stock and stock options issued and exclude stock options issued in tandem with

SARs. Historically, we have issued stock options in tandem with SARs and substantially all stock option plan participants have exercised the SARs instead of the stock options. The numerator we use in calculating both basic and diluted EPS for each period is our reported net income.

Notes to Consolidated Financial Statements

Energy East Corporation

The reconciliation of basic and dilutive average common shares for each period follows:

Year Ended December 31,	2006	2005	2004
(Thousands)			
Basic average common shares outstanding	**146,962**	146,964	146,305
Restricted stock awards	**755**	510	408
Potentially dilutive common shares	**131**	343	313
Options issued with SARs	**(131)**	(343)	(313)
Dilutive average common shares outstanding	**147,717**	147,474	146,713

We exclude from the determination of EPS options that have an exercise price that is greater than the average market price of the common shares during the year. Shares excluded from the EPS calculation were: 2.3 million in 2006, 0.4 million in 2005 and 2.0 million in 2004. (See Note 12 for additional information concerning stock-based compensation.)

Consolidated statements of cash flows: We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	2006	2005	2004
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	**$249,662**	$247,434	$245,992
Income taxes, net of benefits received	**$93,294**	$102,647	$140,823

The amount of capitalized interest was $2 million in 2006 and $1 million in 2005 and 2004.

Decommissioning expense: Other operating expenses for 2004 include nuclear decommissioning expense accruals. As a result of the sale of Ginna in June 2004 we no longer have a decommissioning obligation and will not incur additional decommissioning expense.

Depreciation and amortization: We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 56 years, distribution property - 50 years, generation property - 48 years, gas production property - 31 years, gas storage property - 25 years, and other property - 30 years. RG&E determines depreciation expense for the majority of its generation property using remaining service life rates, which include estimated cost of removal, based on operating license expiration or anticipated closing dates. The remaining service lives of RG&E's generation property range from 1 years for its coal station to 31 years for its hydroelectric stations. Our depreciation accruals were equivalent to 3.1% of average depreciable property for 2006 and 3.3% of average depreciable property for 2005 and 2004.

We charge repairs and minor replacements to operating expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Notes to Consolidated Financial Statements

Energy East Corporation

Estimates: Preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

FIN 48: In July 2006 the FASB released FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with Statement 109 by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or to be taken in a tax return. The evaluation of a tax position is a two-step process. The first step is for an entity to determine if it is more likely than not that a tax position will be sustained upon examination. The second step involves measuring the amount of tax benefit to be recognized in the financial statements based on the largest amount of benefit that meets the prescribed recognition threshold. The difference between the amounts based on that position and the position taken in a tax return is generally recorded as a liability. FIN 48 is effective for fiscal years beginning after December 15, 2006. Upon adoption of FIN 48, the cumulative effect of applying the provisions of FIN 48 must be reported as an adjustment to the opening balance of retained earnings for that fiscal year. We adopted FIN 48 effective January 1, 2007. While we are still in the process of measuring the effect of the adoption, we estimate that the adoption will not have a material effect on our results of operations or financial position.

Goodwill: We record the excess of the cost over fair value of net assets of purchased businesses as goodwill. We evaluate the carrying value of goodwill for impairment at least annually and on an interim basis if there are indications that goodwill might be impaired. We may recognize an impairment if the fair value of goodwill is less than its carrying value. (See Note 4.)

Investments available for sale: We held current investments of $20 million at December 31, 2006, and $193 million at December 31, 2005, which consisted of auction rate securities classified as available-for-sale. Our investments in these securities are recorded at cost, which approximates fair market value due to their variable interest rates, which typically reset every 7 to 35 days. Despite the long-term nature of their stated contractual maturities, we have the ability to quickly liquidate such securities. As a result, we have no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from our current investments. All income generated from these current investments is recorded as interest income.

-

Notes to Consolidated Financial Statements

Energy East Corporation

Other (Income) and Other Deductions:

Year Ended December 31, (Thousands)	2006	2005	2004
Interest and dividend income	**$(16,699)**	$(15,802)	$(12,421)
Allowance for funds used during construction	**(2,266)**	(1,552)	(582)
Gains on energy risk contracts	**(6,158)**	(2,701)	(4,544)
2004 RG&E Electric and Natural Gas Rate Agreement	**-**	-	(6,117)
Earnings from equity investments	**(3,483)**	(3,959)	(3,930)
Environmental recovery	**(8,383)**	-	-
Miscellaneous	**(9,137)**	(8,890)	(7,903)
Total other (income)	**$(46,126)**	$(32,904)	$(35,497)
Losses from disposition of nonutility property	**$916**	$100	$3,543
Losses on energy risk contracts	**6,376**	40	5,727
Recognition of expense resulting from retirement of debt and trust preferred securities	**11,248**	-	-
Donations, civic and political	**3,363**	3,744	1,665
Merger-enabled gas supply savings	**(851)**	796	4,651
Miscellaneous	**3,526**	4,178	217
Total other deductions	**$24,578**	$8,858	$15,803

Principles of consolidation: These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions, except variable interest entities for which we are not the primary beneficiary.

Regulatory assets and liabilities: Pursuant to Statement 71 our operating utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. Our operating utilities also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans.

Notes to Consolidated Financial Statements

Energy East Corporation

At December 31, 2006 and 2005, our Other regulatory assets and liabilities consisted of:

(Thousands)	2006	2005
Statement 106	**$51,819**	$63,780
Customer Hardship Arrearage Forgiveness Program and Three-way Payment Plan	**43,949**	42,222
Loss on sale of RG&E Oswego generating unit	**41,895**	48,371
Asset retirement obligation	**30,808**	9,315
Deferred ice storm costs	**28,811**	32,014
Deferred pension costs	**25,562**	16,771
Stranded cost reconciliation	**24,349**	18,545
Deferred natural gas costs	**21,087**	77,838
RG&E merger costs	**12,406**	24,393
Other	**75,613**	50,924
Total other regulatory assets	**$356,299**	$384,173
Deferred natural gas costs	**$20,567**	$18,095
Economic development	**6,934**	4,213
Pension	**6,527**	-
Nuclear decommissioning	**5,729**	5,555
Overcollection of Gross Receipts Tax	**5,506**	7,860
Accrued earnings sharing	**4,585**	48,075
Other	**43,420**	40,453
Total other regulatory liabilities	**$93,268**	$124,251

Revenue recognition: We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to Maine State Law, since March 1, 2000, CMP has been prohibited from selling power to its retail customers. CMP does not enter into purchase or sales arrangements for power with ISO-NE, the New England Power Pool, or any other independent system operator or similar entity. CMP sells all of its power entitlements under its NUG and other purchase power contracts to unrelated third parties under bilateral contracts.

NYSEG and RG&E enter into power purchase and sales transactions with the NYISO. When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income.

Risk management: The financial instruments we hold or issue are not for trading or speculative purposes.

We use interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. We record amounts paid and received under the agreements as adjustments to the interest expense of the specific debt issues. We also use derivative instruments to mitigate risk resulting from interest rate changes on anticipated future financings and we amortize amounts paid or received under those instruments to interest expense over the life of the corresponding financing.

Notes to Consolidated Financial Statements

Energy East Corporation

NYSEG, RG&E, Energetix and NYSEG Solutions face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's Moody's or S&P credit rating. When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We use electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the electricity is sold.

All of our natural gas operating utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost when the related sales commitments are fulfilled.

We recognize the fair value of our financial electricity contracts, natural gas hedge contracts and interest rate swap agreements as current and noncurrent derivative assets or other current and noncurrent liabilities. Our financial electricity contracts and interest rate swap agreements are designated as cash flow hedging instruments, except for our fixed-to-floating interest rate swap agreement totaling $125 million, which is designated as a fair value hedge. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income, to the extent they are considered effective, until the underlying transaction occurs. We record the ineffective portion of any change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions, as appropriate. We report changes in the fair value of the interest rate swap agreement on our consolidated statements of income in the same period as the offsetting change in the fair value of the underlying debt instrument. We record changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities.

We use quoted market prices to determine the fair value of derivatives and adjust for volatility and inflation when the period of the derivative exceeds the period for which market prices are readily available.

Notes to Consolidated Financial Statements

Energy East Corporation

As of December 31, 2006, the maximum length of time over which we had hedged our exposure to the variability in future cash flows for forecasted energy transactions was 36 months. We estimate that losses of $2 million will be reclassified from accumulated other comprehensive income into earnings in 2007, as the underlying transactions occur.

We have commodity purchases and sales contracts for both capacity and energy that have been designated and qualify for the normal purchases and normal sales exception in Statement 133, as amended.

Statement 123(R): Statement 123(R) is a revision of Statement 123 and requires a public entity to measure the cost of employee services that it receives in exchange for an award of equity instruments based on the grant-date fair value of the award and recognize that cost over the period during which the employee is required to provide service in exchange for the award.

Statement 123(R) also requires a public entity to initially measure the cost of employee services received in exchange for an award of liability instruments (e.g., instruments that are settled in cash) based on the award's current fair value, subsequently remeasure the fair value of the award at each reporting date through the settlement date and recognize changes in fair value during the required service period as compensation cost over that period. We early adopted Statement 123(R) effective October 1, 2005, using the modified version of prospective application. Our adoption of Statement 123(R) did not have a material effect on our financial position, results of operations or cash flows. We describe our share-based compensation plans more fully in Note 12.

As required by Statement 123(R), we no longer record deferred compensation cost for awards of restricted stock, but instead recognize capital in excess of par value and compensation cost for the restricted stock over the estimated vesting period. The estimated vesting period is the period during which the employee is required to provide service in exchange for the award as adjusted based on the expected achievement of performance conditions.

Our restricted stock awards have a retirement eligibility provision. Effective with our adoption of Statement 123(R) we follow the nonsubstantive vesting period approach, according to which an award is considered to be vested for expense recognition purposes when an employee's retention of the award is no longer contingent on providing subsequent service. Therefore, we recognize compensation cost immediately for any new awards of restricted stock to employees who are eligible for retirement on the date of the grant. We follow the nominal vesting period approach for any restricted stock awards granted prior to our adoption of Statement 123(R) and record compensation expense over the estimated vesting period for these restricted stock awards, beginning on the grant date. If an employee retires before the end of the estimated vesting period, we recognize at the date of retirement any remaining unrecognized compensation cost related to that employee's restricted stock. Our pro forma compensation cost for restricted stock for 2006, 2005 and 2004 following the nonsubstantive vesting period approach is not materially different from the compensation cost we recognized following the nominal vesting period approach.

Statement 157: In September 2006 the FASB issued Statement 157. Changes from current practice that will result from the application of Statement 157 relate to the definition of fair value, the methods used to measure fair value, and expanded disclosures about fair value measurements. Statement 157 applies under other accounting pronouncements that require or permit fair value measurements in which the FASB previously concluded that fair value is the relevant measurement attribute. It does not require any new fair value measurements, but may change current practice for some entities. Statement 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged. The provisions are to be applied prospectively, with certain exceptions. A cumulative-effect adjustment to retained earnings is required for application to certain financial instruments. We will adopt Statement 157 effective January 1, 2008. We are currently assessing the effect Statement 157 would have on our results of operations, financial position and cash flows.

Statement 158: In September 2006 the FASB issued Statement 158, which amends FASB Statements No. 87, 88, 106 and 132(R), and requires an employer to:

- recognize the overfunded or underfunded status of defined benefit pension and/or other postretirement plans as an asset or liability in its balance sheet;
- recognize changes in the funded status of such plans in the year in which the changes occur through comprehensive income;
- measure the funded status of a plan as of the date of its year-end balance sheet, and
- disclose in the notes to the annual financial statements certain effects that the delayed recognition of the gains or losses, prior service costs or credits and transition asset or obligation are expected to have on net periodic benefit cost for the next fiscal year.

The funded status of a benefit plan is measured as the difference between plan assets at fair value and the benefit obligation, which is the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for any other postretirement benefit plan. As required by Statement 158, gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost pursuant to Statement 87 or Statement 106 are recognized as a component of other comprehensive income, net of tax. Gains or losses, prior service costs or credits and the transition asset or obligation remaining from the initial application of Statements 87 and 106 that are recognized in accumulated other comprehensive income are adjusted as they are subsequently recognized as components of net periodic benefit cost pursuant to the recognition and amortization provisions of those Statements. However, Energy East's operating companies are rate-regulated entities that meet the criteria to apply Statement 71. Based on our assessments of the facts and circumstances applicable to the jurisdiction and regulatory environment of each operating company, we have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities the above indicated items. Other entities that are not rate-regulated would recognize those items as a component of other comprehensive income and/or include them in accumulated other comprehensive income.

We initially applied the recognition and disclosure provisions of Statement 158 as of December

31, 2006, which increased assets and liabilities, but had no effect on our results of operation or cash flows. Retrospective application of the recognition provisions and measurement provisions is not permitted. We measure our pension and other postretirement plan assets and benefit obligations as of the date of our fiscal year-end balance sheet and therefore have no need to change our measurement date. The incremental effect of applying Statement 158 for our qualified plans on individual line items in our balance sheet as of December 31, 2006, is:

(Thousands)	Before Application of Statement 158	Adjustments	After Application of Statement 158
Regulatory and Other Assets			
Deferred income taxes	$2,539	$(2,539)	-
Pension and other postretirement benefits	-	351,011	$351,011
Other	349,951	6,348	356,299
Total regulatory assets	1,181,094	354,820	1,535,914
Other assets			
Prepaid pension benefits	772,321	(194,965)	577,356
Other	109,341	9,220	118,561
Total other assets	2,454,085	(185,745)	2,268,340
Total Regulatory and Other Assets	3,635,179	169,075	3,804,254
Total Assets	$11,393,326	$169,075	$11,562,401
Current Liabilities			
Deferred income taxes	$10,459	$(10,459)	-
Other	183,611	26,228	$209,839
Total current liabilities	1,297,890	15,769	1,313,659
Regulatory liabilities			
Deferred income taxes	(367)	105,895	105,528
Pension benefits	44,115	83,215	127,330
Other	91,527	1,741	93,268
Total regulatory liabilities	1,106,222	190,851	1,297,073
Other liabilities			
Deferred income taxes	1,191,257	(86,140)	1,105,117
Pension and other postretirement benefits	429,269	101,569	530,838
Other	376,712	(70,429)	306,283
Total other liabilities	2,391,021	(55,000)	2,336,021
Total Regulatory and Other Liabilities	3,497,243	135,851	3,633,094
Total Liabilities	8,521,842	151,620	8,673,462
Accumulated other comprehensive income	(41,234)	17,455	(23,779)
Total Common Stock Equity	2,846,892	17,455	2,864,347
Total Liabilities and Stockholders' Equity	$11,393,326	$169,075	$11,562,401

Taxes: We file a consolidated federal income tax return and allocate income taxes among Energy East and its subsidiaries in proportion to their contribution to consolidated taxable income. The determination and allocation of our income tax provision and its components are outlined and agreed to in the tax sharing agreements among Energy East and its subsidiaries.

-

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. We amortize ITCs over the estimated lives of the related assets.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

Variable interest entities: FIN 46(R), addresses consolidation of variable interest entities. A variable interest entity is an entity that is not controllable through voting interests and/or in which the equity investor does not bear the residual economic risks and rewards. FIN 46(R) requires a business enterprise to consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses. As of March 31, 2004, we applied FIN 46(R) to all entities subject to the interpretation, as required.

We have power purchase contracts with NUGs. However, we were not involved in the formation of and do not have ownership interests in any NUGs. We have evaluated all of our power purchase contracts with NUGs with respect to FIN 46(R) and determined that most of the purchase contracts are not variable interests for one of the following reasons: the contract is based on a fixed price or a market price and there is no other involvement with the NUG, the contract is short-term in duration, the contract is for a minor portion of the NUG's capacity or the NUG is a governmental organization or an individual. One of our NUG contracts expired in April 2006. We are not able to determine if we have variable interests with respect to power purchase contracts with six remaining NUGs because we are unable to obtain the information necessary to: (1) determine if any of the six NUGs is a variable interest entity, (2) determine if an operating utility is a NUG's primary beneficiary or (3) perform the accounting required to consolidate any of those NUGs. We routinely request necessary information from the six NUGs, and will continue to do so, but no NUG has yet provided the requested information. We did not consolidate any NUGs as of December 31, 2006, 2005 or 2004.

We continue to purchase electricity from the six NUGs at above-market prices. We are not exposed to any loss as a result of our involvement with the NUGs because we are allowed to recover through rates the cost of our purchases. Also, we are under no obligation to a NUG if it decides not to operate for any reason. The combined contractual capacity for the remaining six NUGs is approximately 462 MWs. The combined purchases from the six NUGs totaled approximately $352 million in 2006, $376 million in 2005 and $325 million in 2004.

Note 2. Sale of Ginna

In June 2004, after receiving all regulatory approvals, RG&E sold Ginna to CGG. RG&E received at closing $429 million and received in September 2004 an additional $25 million for post-closing adjustments. Our 2004 statement of income reflects a gain on the sale of Ginna of $341 million. The deferral of the asset sale gain, after related taxes of $112 million, is $229 million.

Energy East Corporation

RG&E's Electric Rate Agreement resolved all regulatory and ratemaking aspects related to the sale of Ginna, including providing for an ASGA of $378 million after the post-closing adjustments, and addressing the disposition of the asset sale gain. Upon closing of the sale of Ginna, RG&E transferred $201 million of decommissioning funds to CGG, which has taken responsibility for all future decommissioning funding. RG&E retained $77 million in excess decommissioning funds, which was credited to its customers as part of the ASGA.

Note 3. Impairment of Assets and Disposal of Other Businesses

In keeping with our focus on regulated electric and natural gas delivery businesses, during recent years we have been systematically exiting certain noncore businesses. All businesses sold were previously reported in our Other business segment.

In December 2006 Energy East Telecommunication, Inc. a subsidiary of The Energy Network, Inc. sold its assets for $0.8 million, resulting in no after tax gain or loss. In the fourth quarter of 2005 South Glens Falls Energy, LLC decided to shut down operations of its 67 MW natural gas-fired peaking co-generation facility located in South Glens Falls, New York. Our subsidiary, Cayuga Energy owned 85% of SGF. The determination to shut down operations was based on SGF's inability to recover costs given the current and forecasted prices for natural gas and electricity.

SGF also had an agreement to sell steam that was resulting in ongoing losses. On January 26, 2006, SGF filed for bankruptcy under Chapter 7 of the United States Bankruptcy Code. SGF has ceased operations and in 2005 we recorded an after-tax loss of $5.2 million, representing the impairment of SGF's assets.

In October 2004 Energy East Solutions, Inc., a subsidiary of The Energy Network, Inc., completed the sale of its New England and Pennsylvania natural gas customer contracts and related assets at an after-tax loss of less than $1 million. In July 2004 The Union Water-Power Company, a subsidiary of CMP Group, sold the assets associated with its utility locating and construction divisions at an after-tax loss of $7 million. In 2004 we recognized a loss from discontinued operations of $8 million or 6 cents per share.

In 2003 Energetix, a subsidiary of RGS Energy, sold its subsidiary Griffith Oil Co., Inc. In 2004 we recorded a change in taxes of $1.2 million related to the sale of Griffith Oil to reflect actual taxes in accordance with the filing of our 2003 federal and state income tax returns.

Energy East Corporation

The results of discontinued operations of the businesses sold were:

Year Ended December 31,	2004
(Thousands)	
Component of Energy East Solutions, Inc.	

Revenues	$48,634
Loss from operations of discontinued business	$(859)
Income taxes (benefits)	(142)
Loss from discontinued operations	$(717)
Certain Divisions of The Union Water-Power Company	
Revenues	$13,156
Loss from operations of discontinued business	$(6,250)
Income taxes	151
Loss from discontinued operations	$(6,401)
Griffith Oil Co., Inc.	
Revenues	-
Loss from operations of discontinued business	-
Income taxes	$1,166
Loss from discontinued operations	$(1,166)
Totals for discontinued operations	
Total revenues	$61,790
Total loss from operations of discontinued businesses	$(7,109)
Total income taxes	1,175
Total loss from discontinued operations	$(8,284)

Note 4. Goodwill and Other Intangible Assets

We do not amortize goodwill or intangible assets with indefinite lives (unamortized intangible assets). We test goodwill and unamortized intangible assets for impairment at least annually. We amortize intangible assets with finite lives (amortized intangible assets) and review them for impairment. We completed our annual impairment testing in the third quarter of 2006 and determined that we had no impairment of goodwill or unamortized intangible assets.

Changes in the carrying amount of goodwill at December 31, 2006, are for preaquisition income tax adjustments. The amounts of goodwill by operating segment (in thousands) are:

	Dec. 31, 2006	**Dec. 31, 2005**
Electric Delivery	**$845,296**	$844,491
Natural Gas Delivery	**677,080**	676,588
Other	**3,672**	4,274
Total	**$1,526,048**	$1,525,353

Other Intangible Assets: Our unamortized intangible assets had a carrying amount of $2 million at December 31, 2006, and $19 million at December 31, 2005, and primarily consisted of franchise costs in 2006 and pension assets in 2005. Our amortized intangible assets had a gross carrying amount of $27 million at December 31, 2006 and $31 million at December 31, 2005, and primarily consisted of investments in pipelines and customer lists. Accumulated amortization was $14 million at December 31, 2006 and $18 million at December 31, 2005. Estimated amortization expense for intangible assets is approximately $1 million for each of the next five years, 2007 through 2011.

Note 5. Income Taxes

Year Ended December 31,	2006	2005	2004
(Thousands)			
Current			
Federal	**$108,025**	$87,058	$99,268
State	**16,105**	14,800	19,186
Current taxes charged to expense	**124,130**	101,858	118,454
Deferred			
Federal	**22,396**	55,821	123,517
State	**11,832**	15,438	17,545
Deferred taxes charged to expense	**34,228**	71,259	141,062
ITC adjustments	**(3,103)**	(3,120)	(8,071)
Total for Continuing Operations	**$155,255**	$169,997	$251,445

Our tax expense differed from the expense at the statutory rate of 35% due to the following:

Year Ended December 31,	2006	2005	2004
(Thousands)			
Tax expense at statutory rate	**$145,675**	$149,907	$172,465
Depreciation and amortization not normalized	**7,889**	11,859	2,220
ITC amortization	**(3,119)**	(3,120)	(8,071)
ASGA, Ginna	**-**	-	80,075
State taxes, net of federal benefit	**18,161**	19,654	23,875
Other, net	**(13,351)**	(8,303)	(19,119)
Total for Continuing Operations	**$155,255**	$169,997	$251,445

The effective tax rate for continuing operations was 37% in 2006, 40% in 2005, and 51% in 2004. The increase in 2004 was primarily a result of the regulatory treatment of the deferred gain from RG&E's sale of Ginna. RG&E recorded pretax income of $112 million and income tax expense of $112 million. (See Note 2.)

<u>**Notes to Consolidated Financial Statements**</u>

Energy East Corporation

At December 31, 2006 and 2005, our consolidated deferred tax assets and liabilities consisted of:

	2006	2005
(Thousands)		
Current Deferred Income Tax Assets (Liabilities)		
Derivative assets	**$27,076**	$(110,390)
Other	**66,111**	29,406
Total Current Deferred Income Tax Assets (Liabilities)	**$93,187**	$(80,984)
Noncurrent Deferred Income Tax Liabilities		
Depreciation	**$993,499**	$946,155
Unfunded future income taxes	**103,385**	136,059

Accumulated deferred ITC	**35,320**	38,604
Deferred (gain) on sale of generation assets	**(31,718)**	(49,715)
Pension	**246,955**	170,541
Statement 106 postretirement benefits	**(119,115)**	(135,205)
Derivative (liabilities)	**(4,536)**	(11,132)
Other	**(13,548)**	(75,502)
Total Noncurrent Deferred Income Tax Liabilities	**1,210,242**	1,019,805
Valuation allowance	**403**	-
Less amounts classified as regulatory liabilities		
Deferred income taxes	**105,528**	(13,482)
Noncurrent Deferred Income Tax Liabilities	**$1,105,117**	$1,033,287
Deferred tax assets	**$262,103**	$300,960
Deferred tax liabilities	**1,379,158**	1,401,749
Net Accumulated Deferred Income Taxes Liability	**$1,117,055**	$1,100,789

Energy East and its subsidiaries have New York State loss carryforwards of $17.2 million, which expire between 2020 and 2023, and an associated valuation allowance of $0.4 million.

Note 6. Long-term Debt

Debt owed to subsidiary holding solely parent debentures: The debt owed to a subsidiary holding solely parent debentures consisted of Energy East's 8 1/4% junior subordinated debt securities that were to mature on July 1, 2031, and were held by Energy East Capital Trust I (the Trust). We redeemed all of the junior subordinated debt securities at par on July 24, 2006, financed by the issuance of $250 million of unsecured long-term debt at 6.75%, due in 2036, and by the issuance of short-term debt. We expensed approximately $11 million of unamortized debt expense in July 2006 in connection with the redemption. Also in July 2006 the Trust redeemed, at par, its $345 million, 8 1/4% Capital Securities.

Other long-term debt: At December 31, 2006 and 2005, our consolidated other long-term debt was:

Company		Interest Rates	Maturity	Amount (Thousands) 2006	2005
	First mortgage bonds [1]				
RG&E	Series B, TT, UU & VV	5.84% - 7.60%	2008 - 2033	**$511,000**	$511,000
RG&E	PCN 2004 Series A & B	3.60% - 3.85%	2032	**60,500**	60,500
SCG	Medium Term Note I, II & III	4.57% - 7.95%	2007 - 2035	**219,000**	224,000
SCG	Series W	8.93%	2021	**25,000**	25,000
Berkshire Gas	Series P	10.06%	2019	**10,000**	10,000
Total first mortgage bonds				**825,500**	830,500

Unsecured pollution control notes, fixed

NYSEG	1994 Series A & E	5.90% - 6.00%	2006		-	37,000
NYSEG	1985 Series A, B & D	4.00% - 4.10%	2015		**132,000**	132,000
NYSEG	2004 Series C	3.245%	2034		**100,000**	100,000
RG&E	1998 Series A	5.95%	2033		**25,500**	25,500
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014		**19,500**	19,500
Total unsecured pollution control notes, fixed					**277,000**	314,000
	Unsecured pollution control notes, variable					
NYSEG	2006 Series A	3.75%	2024		**12,000**	-
NYSEG	2005 Series A	3.75%	2026		**65,000**	65,000
NYSEG	2004 Series A & B	3.80% - 3.85%	2027 - 2028		**104,000**	104,000
NYSEG	1994 Series B, C, D1 & D2	3.50% - 3.60%	2029		**175,000**	175,000
RG&E	1997 Series A, B & C	3.38% - 3.50%	2032		**101,900**	101,900
TEN Cos	Industrial Revenue Variable Rate Demand Bonds	3.92%	2025 - 2030		**14,900**	14,900
Total unsecured pollution control notes, variable					**472,800**	460,800
	Various long-term debt					
Energy East	Unsecured Note	5.75%	2006		-	232,350
Energy East	Unsecured Note	8.05%	2010		**200,000**	200,000
Energy East	Unsecured Note	6.75%	2012		**400,000**	400,000
Energy East	Unsecured Note	6.75%	2033		**200,000**	200,000
Energy East	Unsecured Notes	6.75%	2036		**500,000**	-
NYSEG	Unsecured Notes	4.375% - 5.75%	2007 - 2023		**550,000**	450,000
CMP	Series E & F Medium Term Notes	4.25% - 7.00%	2007 - 2035		**310,700**	310,700
CNG	Medium Term Notes Series A, B & C	5.63% - 9.10%	2007 - 2035		**149,000**	149,000
Berkshire Gas	Unsecured Notes	4.76% - 9.60%	2011 - 2021		**36,000**	36,000
Energetix	Promissory Note	8.50%	2007		**3,509**	3,509
TEN Cos	Senior Secured Term Notes	6.90% - 6.99%	2009 - 2010		**30,000**	35,000
NORVARCO	Promissory and Senior Note	7.05% - 10.48%	2020		**16,373**	17,556
Total various long-term debt				**2,395,582**		2,034,115
Obligations under capital leases				**25,187**		26,855
Unamortized premium and discount on debt, net				**(8,592)**		(28,348)
				3,987,477		3,637,922
Less debt due within one year, included in current liabilities				**260,768**		326,527
Total				**$3,726,709**		$3,311,395

1. The first mortgage bonds are secured by liens on substantially all of the respective utility's properties.

Notes to Consolidated Financial Statements

Energy East Corporation

There are federal and state regulatory restrictions on our ability to borrow funds from our utility subsidiaries. While we may be able to borrow funds from our utility subsidiaries by obtaining regulatory approvals and meeting certain conditions, we do not expect to seek such loans. Energy East has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Energy East's debt obligations are guaranteed or secured by its subsidiaries.

At December 31, 2006, other long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years is:

2007	2008	2009	2010	2011
$260,768	$96,347	$148,949	$261,403	$221,925

Cross-default Provisions: Energy East has a provision in its senior unsecured indenture, which provides that its default with respect to any other debt in excess of $40 million will be considered a default under its senior unsecured indenture. Energy East also has a provision in its revolving credit facility, which provides that its default with respect to any other debt in excess of $50 million will be considered a default under its revolving credit facility.

Note 7. Bank Loans and Other Borrowings

Energy East is the sole borrower in a revolving credit facility providing maximum borrowings of up to $300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. Both facilities have expiration dates in 2011 and require fees on undrawn borrowing capacity. Two of our operating utilities have uncommitted bilateral credit agreements for a total of $10 million. The two revolving credit facilities and the two bilateral credit agreements provided for consolidated maximum borrowings of $785 million at December 31, 2006 and 2005. Energy East pays a facility fee of 10 basis points annually on its $300 million revolver and each joint borrower pays a facility fee on its revolver sublimit, ranging from 6 to 10 basis points annually depending on the rating of its unsecured debt.

We use commercial paper and drawings on our credit facilities to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. There was $109 million of such short-term debt outstanding at December 31, 2006, and $121 million outstanding at December 31, 2005. The weighted-average interest rate on short-term debt was 6.0% at December 31, 2006, and 4.6% at December 31, 2005.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated total capitalization, we have amended the facility to exclude from consolidated net worth the balance of 'Accumulated other comprehensive income (loss) ' as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction

on the amount of secured indebtedness Energy East may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.58 to 1.00 at December 31, 2006. We are not in default, and no condition exists that is likely to create a default, under the facility.

In the revolving credit facility in which our operating utilities are joint borrowers, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility was amended to exclude from consolidated net worth the balance of 'Accumulated other comprehensive income (loss)' as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to observe those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. No borrower is in default, and no condition exists that is likely to create a default, under the facility.

Note 8. Preferred Stock Redeemable Solely at the Option of Subsidiaries

At December 31, 2006 and 2005, our consolidated preferred stock was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2006	2005
CMP, 6% Noncallable	$100	-	5,180	**$518**	$518
CMP, 4.60%	100	101.00	30,000	**3,000**	3,000
CMP, 4.75%	100	101.00	50,000	**5,000**	5,000
CMP, 5.25%	100	102.00	50,000	**5,000**	5,000
NYSEG, 3.75%	100	104.00	78,379	**7,838**	7,838
NYSEG, 4.50% (1949)	100	103.75	11,800	**1,180**	1,180
NYSEG, 4.40%	100	102.00	7,093	**709**	709
NYSEG, 4.15% (1954)	100	102.00	4,317	**432**	432
Berkshire Gas, 4.80%	100	100.00	1,651	**165**	204
CNG, 6.00%	100	110.00	4,104	**411**	411
CNG, 8.00% Noncallable	3.125	-	108,706	**339**	339
Total				**$24,592**	$24,631

[1] At December 31, 2006, Energy East and its subsidiaries had 16,731,749 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 775,609 shares of $3.125 par value preferred stock, 600,000 shares of $1 par value preferred stock, 10,000,000 shares of $.01 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 6,000,000 shares of $1 par value preference stock authorized but unissued.

Our subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2004 through 2006:

Subsidiary	Date	Series	Amount (Thousands)
Berkshire Gas	September 16, 2004	4.80%	$5.6
Berkshire Gas	September 15, 2005	4.80%	$39.9

Berkshire Gas	September 15, 2006	4.80%	$39.3
RG&E	May 5, 2004	4.00% F	$12,000
RG&E	May 5, 2004	4.10% H	$8,000
RG&E	May 5, 2004	4.75% I	$6,000
RG&E	May 5, 2004	4.10% J	$5,000
RG&E	May 5, 2004	4.95% K	$6,000
RG&E	May 5, 2004	4.55% M	$10,000
CMP	June 10, 2005	3.50%	$22,000

Voting rights: If preferred stock dividends on any series of preferred stock of a subsidiary, other than the CMP 6% series and the CNG 8.00% series, are in default in an amount equivalent to four full quarterly dividends, the holders of the preferred stock of such subsidiary are entitled to elect a majority of the directors of such subsidiary (and, in the case of the CNG 6.00% series, the largest number of directors constituting a minority of the board) and their privilege continues until all dividends in default have been paid. The holders of preferred stock, other than the CMP 6% series and the CNG 8.00% series, are not entitled to vote in respect of any other matters except those, if any, in respect of which voting rights cannot be denied or waived under some mandatory provision of law, and except that the charters of the respective subsidiaries contain provisions to the effect that such holders shall be entitled to vote on certain matters affecting the rights and preferences of the preferred stock.

Holders of the CMP 6% series and the CNG 8.00% series are entitled to one vote per share and have full voting rights on all matters.

Note 9. Commitments and Contingencies

Capital spending: We have commitments in connection with our capital spending program. We plan to invest over $3 billion in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. We expect that over one-half of our capital spending will be paid for with internally generated funds and the remainder through the issuance of debt and equity securities. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, increased transmission capacity, necessary improvements to existing facilities, the installation of an advanced metering infrastructure and compliance with environmental requirements and governmental mandates.

Nonutility generator power purchase contracts: We expensed approximately $560 million for NUG power in 2006, $631 million in 2005, and $613 million in 2004. We estimate that our NUG power purchases will be $568 million in 2007, $392 million in 2008, $229 million in 2009, $84 million in 2010 and $85 million in 2011.

-

Nuclear entitlement power purchase contracts: In connection with our sales of nuclear generating assets in 2004 and 2001, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately $258 million for nuclear entitlement power in 2006, $263 million in 2005, and $199 million in 2004. We estimate that our nuclear entitlement power purchases will be $281 million in 2007, $287 million in 2008, $293 million in 2009, $309 million in 2010, and $276 million in 2011.

NYISO billing adjustment: The NYISO frequently bills market participants on a retroactive basis when it determines that billing adjustments are necessary. Such retroactive billings can cover several months or years and cannot be reasonably estimated. NYSEG and RG&E record transmission or supply revenue or expense, as appropriate, when revised amounts are available. The two companies have developed an accrual process that incorporates available information about retroactive NYISO billing adjustments as provided to all market participants. However, on an ongoing basis, they cannot fully predict either the magnitude or the direction of any final billing adjustments.

NYPSC proceeding on NYSEG's accounting for OPEB: On August 23, 2006, the NYPSC issued its decision in the NYSEG rate case. Among other things, the NYPSC instructed the ALJ to open a separate proceeding regarding the NYPSC staff's position that NYSEG should have retained $57 million of interest in its OPEB reserve and used it to reduce rate base. A proceeding has been opened and hearings on the issues raised by the NYPSC staff are currently scheduled for July 2007. NYPSC acceptance of its staff's position would result in NYSEG treating all or a portion of the $57 million as an addition to its internal OPEB reserve, with a corresponding charge to income. While NYSEG is vigorously opposing staff on these issues, contending that the NYPSC staff is engaged in retroactive ratemaking, it cannot predict how this matter will be resolved.

Note 10. Environmental Liability and Nuclear Decommissioning

Environmental liability: From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric and natural gas service.

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties who may be liable for costs incurred to remediate certain hazardous substances at 22 waste sites. The 22 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 22 sites, 13 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, three are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and nine sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $2 million related to 12 of the 22 sites. We have paid remediation costs related to the remaining 10 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $4 million related to another 12 sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 60 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, four sites are part of Maine's Voluntary Response Action Program and one of those four sites is part of Maine's Uncontrolled Sites Program, three sites are included in the Connecticut Inventory of Hazardous Waste Sites, and three sites are on the Massachusetts Department of Environmental Protection's list of confirmed disposal sites. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 47 of the 60 sites.

Our estimate for all costs related to investigation and remediation of the 60 sites ranges from $162 million to $290 million at December 31, 2006. Our estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $162 million at December 31, 2006, and $161 million at December 31, 2005. We recorded a corresponding regulatory asset, net of insurance recoveries, since we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of our environmental liability accruals, which are expected to be paid through the year 2017, have been established on an undiscounted basis. Some of our operating utility subsidiaries have received insurance settlements during the last three years, which they generally accounted for as reductions to their related regulatory assets. The DTE allows utilities in Massachusetts to retain a percentage share of insurance proceeds for shareholders.

Nuclear decommissioning: CMP has ownership interests in three nuclear generating companies in New England, which it accounts for under the equity method. All three companies have permanently shut down their facilities which have been decommissioned or are in the process of being decommissioned.

Each of the three nuclear generating companies has an established NRC licensed independent spent fuel storage installation on site to store spent nuclear fuel in dry casks until the DOE takes the fuel for disposal.

	Maine Yankee	Yankee Atomic	Connecticut Yankee
($ in Millions)			
Ownership share	38%	9.5%	6%
2006 decommissioning and spent fuel storage costs	$24.1	$4.7	$7.3
Share of remaining decommissioning and other costs (in 2006 dollars)	$62.1	$7.3	$19.8
Equity interest at December 31, 2006	$6.0	-	$2.6

Maine Yankee's decommissioning was completed in 2005, Yankee Atomic's decommissioning was completed during 2006 and Connecticut Yankee's decommissioning is scheduled to be completed during 2007. Connecticut Yankee increased its decommissioning collections to $93 million annually as of January 2005. CMP's share of that increase is approximately $6 million. Under Maine statutes, CMP is allowed to recover in rates any increases in decommissioning costs and pursuant to its 2005 stranded cost settlement with the MPUC, CMP began to collect the higher decommissioning costs for Connecticut Yankee in March 2005 and for Yankee Atomic in March 2006.

Note 11. Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. The fair values are based on the quoted market prices for the same or similar issues of the same remaining maturities.

December 31,	2006		2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
Noncurrent investments - classified as available-for-sale	**$85,386**	**$85,457**	$88,432	$88,432
Debt owed to affiliate	**-**	**-**	$355,670	$358,817
First mortgage bonds	**$824,625**	**$863,903**	$829,551	$922,079
Pollution control notes, fixed	**$277,000**	**$279,143**	$314,000	$322,510
Pollution control notes, variable	**$472,800**	**$472,800**	$460,800	$460,800
Various long-term debt	**$2,356,290**	**$2,439,918**	$2,006,716	$2,150,762

The carrying amounts for cash and cash equivalents, current investments available for sale, notes payable, derivative assets, derivative liabilities and interest accrued approximate their estimated fair values.

-

Note 12. Share-Based Compensation

As of December 31, 2006, we have two share-based compensation plans, which are described below. The total compensation cost recognized in income for those plans for the years ended

December 31 was: $12.0 million for 2006, $4.1 million for 2005 and $21.1 million for 2004. The total income tax benefit recognized in income for the share-based compensation arrangements for the years ended December 31 was: $4.8 million for 2006, $1.7 million for 2005 and $8.4 million for 2004.

Stock options/SARs: Under our 2000 Stock Option Plan (the Plan), which was approved by our shareholders, we may grant to senior management and certain other key employees stock options and SARs for up to 13 million shares of Energy East's common stock. Awards are intended to more closely align the financial interests of management with those of our shareholders by providing long-term incentives to those individuals who can significantly affect our future growth and success. Our policy is to grant SARs in tandem with any stock options granted. Employees may choose to exercise either the SARs, which are settled in cash, or the stock options. The exercise price of stock options/SARs granted is the market price of Energy East's common stock on the last trading date prior to the date of grant. The stock options/SARs generally vest one-third upon grant, one-third on the first day of the new year following their grant and the last third a year later, subject to, with certain exceptions, continuous employment. All stock options/SARs expire 10 years after the grant date. The Compensation and Management Succession Committee of Energy East's Board of Directors, which administers the Plan, may in its discretion take one or more of specified actions in order to preserve a participant's rights under an award in the event of a change in control (as defined in the Plan).

Effective with our adoption of Statement 123(R) on October 1, 2005, (see Note 1) we began estimating the fair value of each stock option/SAR award using the Black-Scholes-Merton option valuation model and the assumptions noted in the table below. In accordance with Statement 123(R), we measure the fair value of the stock options/SARs on the date of grant, when we begin to recognize compensation cost, and remeasure the fair value at the end of each reporting period. We incur a liability for our stock option plan awards in accordance with Statement 123(R) because employees can request that the awards be settled in cash rather than by issuing equity instruments. The liability at the reporting date is based on the fair value at that date, and the compensation cost for the reporting period then ended is based on the percentage of required service that has been rendered at that date. We base the expected volatility and the dividend yield on 36-month historic averages for Energy East's common stock. The expected term of options/SARs granted represents the period of time that we expect the options/SARs to be outstanding, which we derive using the simplified method allowed by the SEC. An expected term derived using the simplified method is essentially one-half of the remaining contractual term. The risk-free rate for each option is based on the U.S. Treasury yield curve in effect at the end of the reporting period for maturities consistent with the expected term.

	2006	**2005**
Expected volatility	**12.42%**	13.93%
Expected dividends	**4.49%**	4.46%
Expected term (in years)	**0.2-5.0**	0.7-5.0
Risk-free rate	**4.58%-4.99%**	4.19%-4.36%

We applied APB 25, as permitted by Statement 123, to account for our stock-based compensation prior to our adoption of Statement 123(R). In applying APB 25 we incurred a liability for our stock options/SARs, as explained above, and used the intrinsic value method to determine the liability and related compensation during the nine months ended September 30, 2005, and the year 2004. Statement 123 required the amount of the liability for awards that call for settlement in cash to be measured each period based on the current stock price, which produced the same result as using the intrinsic value method in applying APB 25 for such awards.

The following table provides a summary of stock option/SAR activity under the Plan and other information, for the year ended and as of December 31, 2006.

	Stock Options/ SARs	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (Thousands)
Outstanding at January 1, 2006	3,159,988	$23.81		
Options/SARs granted	788,880	$25.11		
SARs exercised	103,495	$21.58		
Options/SARs forfeited or expired	186,818	$26.22		
Outstanding at December 31, 2006	3,658,555	$24.03	6.95	$4,477
Exercisable at December 31, 2006	2,706,652	$23.75	6.17	$4,141

The weighted-average grant-date fair value of stock options/SARs granted during the years ended December 31 was: $2.47 per share for 2006, $2.84 per share for 2005 and $2.93 per share for 2004. The total intrinsic value of share-based liabilities paid during the years ended December 31 was: $0.3 million for 2006, $10.5 million for 2005 and $13.4 million for 2004.

Restricted stock: We have a Restricted Stock Plan for our common stock under which an aggregate of two million shares may be granted, subject to adjustment. We award shares of restricted stock to selected employees, which shares are issued in the name of the employee, who has all the rights of a shareholder subject to certain restrictions on transferability and a risk of forfeiture. The restricted shares generally vest no later than January 1 of the sixth year after the award is granted and based on the conditions outlined in the restricted stock award grants, including the achievement of targeted shareholder returns. We issue shares of restricted stock out of Energy East's treasury stock. We repurchased 250,000 shares of our common stock in February 2006, primarily for grants of restricted stock. The grant-date fair value of shares of restricted stock awarded is based on the market price of Energy East's common stock on the date of the restricted stock award and is not subsequently remeasured. We generally expense the compensation cost for restricted stock ratably over the requisite service period; however, compensation cost for certain shares may be expensed immediately or over shorter periods based on the achievement of performance criteria or the retirement provision included in the Restricted Stock Plan. The weighted-average grant date fair value per share of restricted stock granted during the years ended December 31 was: $24.75 for 2006, $26.42 for 2005 and $23.90 for 2004.

Energy East Corporation

The following table provides a summary of restricted stock activity and other information for the year ended and as of December 31, 2006:

Restricted Stock Plan	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	576,278	$24.29
Granted	273,733	$24.75
Vested	(49,825)	$23.95
Forfeited	(750)	$25.37
Nonvested at December 31, 2006	799,436	$24.46

As of December 31, 2006, there was $4.6 million of total unrecognized compensation cost related to shares granted pursuant to the Restricted Stock Plan, which we expect to recognize over a weighted-average period of less than one year. The total fair value of shares vested during the years ended December 31 was: $1.2 million for 2006, $2.1 million for 2005 and $0.7 million for 2004.

Notes to Consolidated Financial Statements

Energy East Corporation

Note 13. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2004	2004 Change	Balance December 31, 2004	2005 Change	Balance December 31, 2005	2006 Change (1)	Bala Decem 31, 2
(Thousands)							
Unrealized gains (losses) on investments:							
Unrealized holding gains during period, net of income tax (expense) of, $(316) for 2004, $(210) for 2005, and $(964) for 2006		$491		$333		$1,454	
Net unrealized (losses) gains on investments	$(896)	491	$(405)	333	$(72)	1,454	$1,3
Minimum pension liability adjustment, net of income tax benefit (expense) of $8,114 for 2004, $8,674 for 2005 and $(43,850) for 2006	(40,120)	(7,915)	(48,035)	(16,983)	(65,018)	65,018	
Adjustment to initially apply Statement 158 for nonqualified plans, net of income tax benefit of $11,153 for 2006						(16,817)	(16,8
Unrealized gains (losses) on derivatives qualified as hedges:							
Unrealized gains during period on derivatives qualified as hedges, net of income tax (expense) benefit of $(5,061) for 2004, $(107,041) for 2005 and $112,687 for 2006		8,964		167,352		(174,459)	
Reclassification adjustment for (gains) included in net income, net of income tax expense (benefit) of $22,037							

for 2004, $11,987 for 2005 and $(7,843) for 2006		(33,887)		(18,056)		11,940	
Net unrealized gains (losses) on derivatives qualified as hedges(2)	29,802	(24,923)	4,879	149,296	154,175	(162,519)	(8,3
Accumulated Other Comprehensive Income (Loss)	$(11,214)	$(32,347)	$(43,561)	$132,646	$89,085	$(112,864)	$(23,7

(1) The reduction in the minimum pension liability includes $17.4 million for the adjustment to initially apply Statement 158.

(2) See Risk management in Note 1.

Notes to Consolidated Financial Statements

Energy East Corporation

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based on years of service and final average salary. We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually.

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2006	**2005**	**2006**	**2005**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$2,366,748**	$2,254,209	**$536,997**	$559,977
Service cost	**37,443**	35,379	**5,852**	5,775
Interest cost	**127,197**	127,785	**29,319**	30,719
Plan participants' contributions	**-**	-	**25**	642
Plan amendments	**-**	418	**247**	-
Actuarial loss (gain)	**(93,685)**	81,844	**(5,728)**	(23,686)
Benefits paid	**(135,710)**	(132,887)	**(38,275)**	(36,430)
Federal subsidy on benefits paid	**-**	-	**2,006**	-
Benefit obligation at December 31	**$2,301,993**	$2,366,748	**$530,443**	$536,997
Change in plan assets				
Fair value of plan assets at January 1	**$2,584,525**	$2,475,494	**$31,128**	$32,105
Actual return on plan assets	**366,210**	187,449	**3,306**	1,516
Employer contributions	**400**	54,469	**28,125**	26,463
Plan participants' contributions	**-**	-	**25**	642
Benefits paid	**(135,710)**	(132,887)	**(25,283)**	(29,598)
Fair value of plan assets at December 31	**$2,815,425**	$2,584,525	**$37,301**	$31,128
Funded status at December 31	**$513,432**	$217,777	**$(493,142)**	$(505,869)
Unrecognized net actuarial loss (1)		$481,244		$66,349
Unrecognized prior service cost (benefit) (1)		42,810		(36,770)
Unrecognized net transition obligation (1)		-		47,599

Total unrecognized amounts	$524,054	$77,178
Prepaid (accrued) benefit cost	$741,831	$(428,691)

[1] At December 31, 2006, these amounts for pension benefits and postretirement benefits are included in regulatory assets or regulatory liabilities, as appropriate, due to the application of Statement 158 and in accordance with Statement 71. See Statement 158 disclosure in Note 1.

	Pension Benefits		Postretirement Benefits	
Amounts recognized in the balance sheet	**2006**	**2005**	**2006**	**2005**
Noncurrent assets	**$577,356**		**-**	
Current liabilities	**-**		**$(26,228)**	
Noncurrent liabilities	**(63,924)**		**(466,914)**	
	$513,432		**$(493,142)**	
Prepaid benefit cost		$741,831		-
Accrued benefit cost		-		$(428,691)
Additional minimum liability		(185,791)		-
Intangible assets		6,595		-
Regulatory liabilities		76,914		-
Accumulated other comprehensive income		102,282		-
Net amount recognized		$741,831		$(428,691)

Notes to Consolidated Financial Statements

Energy East Corporation

The minimum liability for pension benefits included in other comprehensive income increased $20 million in 2005. We recorded a minimum pension liability of $186 million at December 31, 2005, as required by Statement 87. We recognized the effect of the minimum pension liability in other long-term liabilities, intangible assets, regulatory liabilities and other comprehensive income, as appropriate. That treatment was prescribed when the accumulated benefit obligation in the plan exceeded the fair value of the underlying pension plan assets and accrued pension liabilities. The increase in the unfunded accumulated benefit obligation in 2005 was primarily due to a decrease in the assumed discount rate. The minimum pension liability was eliminated and related amounts reversed based on their balances at December 31, 2006, due to the application of Statement 158. See Statement 158 disclosure in Note 1.

As explained in Note 1, we have determined that all of our operating companies are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to Statement 158. Amounts recognized in regulatory assets or regulatory liabilities at December 31, 2006, consist of:

	Pension Benefits	Postretirement Benefits
(Thousands)		
Net loss (gain)	**$220,806**	**$51,798**
Prior service cost (benefit)	**$38,082**	**$(28,723)**
Transition obligation	**-**	**$40,800**

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $2.1 billion for 2006 and $2.2 billion for 2005.

CMP's, CNG's and SCG's postretirement benefits were partially funded at December 31, 2006 and 2005.

Information for pension plans with an accumulated benefit obligation in excess of plan assets December 31,	2006	2005
(Thousands)		
Projected benefit obligation	**$440,847**	$569,560
Accumulated benefit obligation	**$395,586**	$511,653
Fair value of plan assets	**$383,046**	$456,593

Notes to Consolidated Financial Statements

Energy East Corporation

	Pension Benefits			Postretirement Benefits		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
(Thousands)						
Components of net periodic benefit cost						
Service cost	**$37,443**	$35,379	$32,069	**$5,852**	$5,775	$6,082
Interest cost	**127,197**	127,785	130,891	**29,319**	30,719	34,672
Expected return on plan assets	**(221,702)**	(214,012)	(206,120)	**(1,693)**	(2,248)	(2,480)
Amortization of prior service cost (benefit)	**4,736**	4,994	4,650	**(7,504)**	(7,577)	(7,273)
Amortization of net loss (gain)	**22,245**	15,887	(1,106)	**6,784**	8,630	4,968
Amortization of transition (asset) obligation	**-**	-	(1,230)	**6,800**	6,800	8,001
Curtailment	**-**	-	(148)	**-**	-	230
Settlement charge	**-**	-	12,186	**-**	-	(6,131)
Net periodic benefit cost	**$(30,081)**	$(29,967)	$(28,808)	**$39,558**	$42,099	$38,069

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred at December 31 was $52 million for 2006 and $59 million for 2005. We expect to recover any deferred postretirement costs by 2012. We are amortizing over 20 years the transition obligation for postretirement benefits that resulted from the adoption of Statement 106.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ended December 31, 2007	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss (gain)	$16,824	$5,494
Estimated prior service cost (benefit)	$4,524	$(7,433)
Estimated transition obligation	-	$6,800

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2006	2005	Postretirement Benefits 2006	2005
Discount rate	**5.75%**	5.50%	**5.75%**	5.50%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

Notes to Consolidated Financial Statements

Energy East Corporation

As of December 31, 2006, we increased our discount rate from 5.50% to 5.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31,	Pension Benefits 2006	2005	2004	Postretirement Benefits 2006	2005	2004
Discount rate	**5.50%**	5.75%	6.25%	**5.50%**	5.75%	6.25%
Expected long-term return on plan assets	**8.75%**	8.75%	8.75%	**6.00%**	8.75%	8.75%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes. That analysis considered current capital market conditions and projected conditions. Given the current low interest rate environment, we selected an assumption of 8.75% per year, which is lower than the rate that would otherwise be determined solely based on historical returns. The operating companies amortize unrecognized actuarial gains and losses either over ten years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates at December 31,	2006	2005
Health care cost trend rate assumed for next year	**9.0%**	10.0%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2011**	2011

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	$1,733	$(1,438)
Effect on postretirement benefit obligation	$25,152	$(21,497)

Plan assets: Our weighted-average asset allocations at December 31, 2006 and 2005, by asset category, are:

	Pension Benefits			Postretirement Benefits		
Asset Category	**Target Allocation**	**2006**	**2005**	**Target Allocation**	**2006**	**2005**
Equity securities	58%	**64%**	64%	50%	**47%**	56%
Debt securities	27%	**24%**	28%	45%	**40%**	37%
Real estate	5%	**4%**	2%	-	**-**	-
Other	10%	**8%**	6%	5%	**13%**	7%
Total	100%	**100%**	100%	100%	**100%**	100%

-

Our pension benefits plan assets are held in a master trust with a trustee and our postretirement benefits plan assets are held with two trustees in multiple VEBA and 401(h) arrangements. Those assets are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our pension benefits plan assets through the utilization of multiple asset managers and systematic allocation to investment management styles, providing broad exposure to different segments of the fixed income and equity markets; and for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets.

Equity securities did not include any Energy East common stock at December 31, 2006 and 2005.

Contributions: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute between $10 and $20 million to our pension benefits plans and approximately $14 million to our other postretirement benefit plans in 2007.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2007	$132,395	$52,409	$3,515
2008	$137,948	$55,559	$3,964
2009	$143,902	$59,210	$4,360
2010	$150,746	$62,852	$4,709
2011	$158,578	$66,584	$4,971
2012 - 2016	$870,437	$362,159	$29,885

Notes to Consolidated Financial Statements

Energy East Corporation

Note 15. Segment Information

Selected financial information for our operating segments is presented in the table below. Our electric delivery segment consists of our regulated transmission, distribution and generation operations in New York and Maine and our natural gas delivery segment consists of our regulated transportation, storage and distribution operations in New York, Connecticut, Maine and Massachusetts. We measure segment profitability based on net income. Other includes primarily our energy marketing companies, interest income, intersegment eliminations and our other nonutility businesses.

(Thousands)	Electric Delivery	Natural Gas Delivery	Other	Total
2006				
Operating Revenues	**$3,023,037**	**$1,697,601**	**$510,027**	**$5,230,665**
Depreciation and Amortization	**$187,587**	**$86,728**	**$8,253**	**$282,568**
Interest Charges, Net	**$215,054**	**$86,263**	**$7,507**	**$308,824**
Income Taxes (Benefits)	**$117,184**	**$44,744**	**$(6,673)**	**$155,255**
Net Income (Loss)	**$179,982**	**$78,166**	**$1,684**	**$259,832**
Total Assets	**$7,184,016**	**$4,073,320**	**$305,065**	**$11,562,401**
Capital Spending	**$253,103**	**$142,881**	**$12,247**	**$408,231**
2005				
Operating Revenues	$2,969,558	$1,783,547	$545,438	$5,298,543
Depreciation and Amortization	$178,806	$85,050	$13,361	$277,217
Interest Charges, Net	$207,074	$81,365	$458	$288,897
Income Taxes	$116,310	$45,752	$7,935	$169,997
Net Income (Loss)	$206,117	$70,121	$(19,405)	$256,833
Total Assets	$7,175,864	$4,136,568	$175,276	$11,487,708
Capital Spending	$205,402	$119,266	$6,626	$331,294
2004				
Operating Revenues	$2,781,322	$1,549,150	$426,220	$4,756,692
Depreciation and Amortization	$196,782	$88,998	$6,677	$292,457
Interest Charges, Net	$194,744	$77,700	$4,446	$276,890
Income Taxes	$203,898	$38,229	$9,318	$251,445
Net Income (Loss)	$171,653	$64,139	$(6,455)	$229,337
Total Assets	$6,738,511	$3,851,242	$206,869	$10,796,622
Capital Spending	$185,544	$107,735	$5,984	$299,263

Notes to Consolidated Financial Statements

Energy East Corporation

Note 16. Quarterly Financial Information (Unaudited)

Quarter Ended	March 31	June 30	September 30	December 31
(Thousands, except per share amounts)				
2006				
Operating Revenues	**$1,695,611**	**$1,112,825**	**$1,090,354**	**$1,331,875**
Operating Income	**$294,441**	**$117,907**	**$99,911**	**$191,233**
Net Income	**$133,241**	**$28,285**	**$21,012**	**$77,294**
Earnings per Share, basic	**$.91**	**$.19**	**$.14**	**$.53**
Earnings per Share, diluted	**$.90**	**$.19**	**$.14**	**$.53**
Dividends Declared per Share	**$.29**	**$.29**	**$.29**	**$.30**
Average Common Shares Outstanding, basic	**147,034**	**146,903**	**146,903**	**147,010**
Average Common Shares Outstanding, diluted	**147,679**	**147,678**	**147,702**	**147,809**
Common Stock Price [1]				
High	**$25.57**	**$25.39**	**$25.20**	**$25.66**
Low	**$22.98**	**$22.18**	**$23.36**	**$23.62**
2005				
Operating Revenues	$1,637,278	$1,081,945	$1,095,931	$1,483,389
Operating Income	$320,817	$98,301	$94,359	$179,678
Net Income	$154,366	$17,365	$21,324	$63,778
Earnings per Share, basic	$1.05	$.12	$.14	$.43
Earnings per Share, diluted	$1.05	$.12	$.14	$.43
Dividends Declared per Share	$.275	$.275	$.275	$.29
Average Common Shares Outstanding, basic	146,875	146,831	147,008	147,125
Average Common Shares Outstanding, diluted	147,196	147,390	147,588	147,701
Common Stock Price [1]				
High	$26.95	$30.07	$29.35	$25.95
Low	$24.98	$25.09	$24.82	$22.50

[1] Our common stock is listed on the New York Stock Exchange. The number of shareholders of record was 29,984 at December 31, 2006.

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
of Energy East Corporation and Subsidiaries:

We have completed integrated audits of Energy East Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Energy East Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Energy East Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 28, 2007

ENERGY EAST CORPORATION

SCHEDULE II - Consolidated Valuation and Qualifying Accounts

Years Ended December 31, 2006, 2005 and 2004

Classification	Beginning of Year	Additions	Write-offs [1]	Adjustments[2]	End of Year
(Thousands)					
2006					
Allowance for Doubtful Accounts - Accounts Receivable	$53,112	$58,475	$(59,058)	$6,724	$59,253
Income Tax Valuation Allowance	-	$400	-	-	$400
2005					
Allowance for Doubtful Accounts - Accounts Receivable	$45,344	$63,166	$(64,355)	$8,957	$53,112
2004					
Allowance for Doubtful Accounts - Accounts Receivable	$52,848	$45,334	$(46,645)	$(6,193)	$45,344

[1] Uncollectible accounts charged against the allowance, net of recoveries.

(2)Represents changes in the estimate of the write-offs that will not be recovered in rates.

Management's Narrative Analysis of Results of Operations

Rochester Gas and Electric Corporation

RG&E meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format and is therefore presenting a management's narrative analysis of the results of operations as specified in General Instruction I(2)(a) of Form 10-K.

RG&E's electric delivery business consists of its regulated electricity transmission and distribution operations in western New York. It also generates electricity from its one coal-fired plant, three gas turbines and several smaller hydroelectric stations. RG&E's natural gas delivery business consists of transporting, storing and distributing natural gas.

Earnings

RG&E's earnings for 2006 increased $3 million compared to 2005, primarily because of a $9 million increase for higher net margins on electricity sales, partially offset by higher income taxes as a result of tax adjustments that lowered tax expense in 2005.

Operating Results for the Electric Delivery Business

	2006	2005
(Thousands)		
Operating Revenues		
Retail	**$432,821**	$439,018
Wholesale	**213,675**	219,026
Other	**84,689**	33,115
Total Operating Revenues	**731,185**	691,159
Operating Expenses		
Electricity purchased and fuel used in generation	**321,524**	296,009
Other operating and maintenance expenses	**167,996**	173,218
Depreciation and amortization	**52,617**	53,607
Other taxes	**46,881**	42,367
Total Operating Expenses	**589,018**	565,201
Operating Income	**$142,167**	$125,958

Operating Revenues: The $40 million increase in operating revenues for 2006 was primarily the result of:

- An increase of $34 million in average delivery prices resulting from higher transition charges,
- An increase of $13 million due to higher market prices for electric energy sold under various commodity options where RG&E provides supply,
- An increase of $25 million resulting from lower accruals under the earnings sharing mechanism including $9 million in the first quarter for the finalization of the actual earnings sharing amount for 2005 per RG&E's annual compliance filing, and

- An increase in other revenues of $25 million, primarily reflecting credits from RG&E's ASGA to recover higher purchased power costs related to Ginna.

Those increases were partially offset by:

- A decrease of $5 million due to lower wholesale revenues,
- A decrease of $5 million resulting from lower retail delivery volumes, and
- A decrease of $48 million resulting from lower electricity sales under RG&E's commodity programs where RG&E provides supply.

Management's Narrative Analysis of Results of Operations

Rochester Gas and Electric Corporation

Operating Expenses: The $24 million increase in operating expenses for 2006 was primarily the result of:

- An increase of $26 million for purchased power costs primarily to Ginna purchases, and
- An increase of $5 million in other taxes.

Those increases were partially offset by a reduction in pension expense of $5 million.

Operating Results for the Natural Gas Delivery Business

	2006	2005
(Thousands)		
Operating Revenues		
Retail	**$378,847**	$409,062
Other	**6,261**	5,305
Total Operating Revenues	**385,108**	414,367
Operating Expenses		
Natural gas purchased	**244,060**	270,647
Other operating and maintenance expenses	**53,690**	59,009
Depreciation and amortization	**18,668**	19,251
Other taxes	**22,749**	23,029
Total Operating Expenses	**339,167**	371,936
Operating Income	**$45,941**	$42,431

Operating Revenues: The $29 million decrease in operating revenues for 2006 was primarily the result of:

- A decline of $53 million due to lower deliveries because of warmer weather.

That decrease was partially offset by:

- An increase of $15 million due to higher purchased gas costs that were passed on to customers, and
- An increase of $8 million for accruals under the weather normalization mechanism.

Operating Expenses: The $33 million decrease in operating expenses for 2006 was primarily the result of:

- A decrease of $5 million in various operating and maintenance costs, and
- A decrease of $27 million in purchased natural gas costs due to lower sales volumes.

New Accounting Standards

The FASB released FIN 48 in July 2006 and issued Statements 157 and 158 in September 2006. See Item 8 - Note 1 to RG&E's Financial Statements for explanations about these new accounting standards and when they will become or became effective.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Rochester Gas and Electric Corporation

Market risk represents the risk of changes in value of a financial or commodity instrument, derivative or nonderivative, caused by fluctuations in interest rates and commodity prices. The following discussion of RG&E's risk management activities includes "forward-looking" statements that involve risks and uncertainties. Actual results could differ materially from those contemplated in the "forward-looking" statements. RG&E handles market risks in accordance with established policies, which may include various offsetting, nonspeculative derivative transactions. (See Item 8 - Note 1 to RG&E's Financial Statements.)

The financial instruments RG&E holds or issues are not for trading or speculative purposes. RG&E's quantitative and qualitative disclosures below relate to the following market risk exposure categories: Interest Rate Risk, Commodity Price Risk and Other Market Risk.

Interest Rate Risk: RG&E is exposed to risk resulting from interest rate changes on variable-rate debt and commercial paper. RG&E uses interest rate swap agreements to manage the risk f increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. RG&E records amounts paid and received under those agreements as adjustments to the interest expense of the specific debt issues. After giving effect to those agreements RG&E estimates that, at December 31, 2006, a 1% change in average interest rates would change its annual interest expense for variable-rate debt by about $1 million. Pursuant to its current rate plans, RG&E defers any changes in variable-rate interest expense. (See Item 8 - Notes 5, 6 and 10 to RG&E's Financial Statements.)

RG&E also uses derivative instruments to mitigate risk resulting from interest rate changes on anticipated future financings, and amortizes amounts paid and received under those instruments to interest expense over the life of the related financing.

Commodity Price Risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas industries. RG&E manages this risk through a combination of regulatory mechanisms, such as allowing for the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. These measures mitigate RG&E's commodity price exposure, but do not completely eliminate it.

RG&E's current electric rate plan offers its retail customers choice in their electricity supply including fixed and variable rate options and an option to purchase electricity supply from an ESCO. During the fourth quarter of 2006, RG&E's electric customers chose their supply options for 2007. Approximately 79% of RG&E's total electric load is now provided by an ESCO or at the market price. RG&E's exposure to fluctuations in the market price of electricity is limited to the load required to serve those customers who select the fixed rate option, which combines delivery and supply service at a fixed price. During 2006 RG&E used electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity required to serve customers who select the fixed rate option. It included the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. RG&E's owned electric

-

generation and long-term supply contracts significantly reduce its exposure to market fluctuations for procurement of its fixed rate option electricity supply, and reduce the volatility of rates for those customers that have chosen a variable rate option. RG&E expects that its owned generation and long-term supply contracts will be sufficient to meet its fixed price load requirements in 2007.

RG&E has a purchased gas adjustment clause that allows it to recover through rates any changes in the market price of purchased natural gas, substantially eliminating its exposure to natural gas price risk. RG&E uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. It includes the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. RG&E records changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities.

RG&E faces risks related to counterparty performance on hedging contracts due to counterparty credit default. RG&E, in conjunction with Energy East, has developed a matrix of unsecured credit thresholds that are dependent on a counterparty's Moody's or S&P credit rating. When Energy East's exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or RG&E will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

<u>Other Market Risk</u>: RG&E's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates may cause RG&E to recognize increased or decreased pension income or expense. RG&E's pension income would change by approximately $1 million if either its expected return on plan assets or its discount rate were to change by 1/4%. Under its Electric and Natural Gas Rate Agreement, RG&E defers changes in pension income resulting from changes in market conditions. (See Item 8 - Note 12 to RG&E's Financial Statements.)

Rochester Gas and Electric Corporation
Statements of Income

Year Ended December 31,	2006	2005	2004
(Thousands)			
Operating Revenues			
Electric	**$731,185**	$691,159	$664,794
Natural gas	**385,108**	414,367	369,263
Total Operating Revenues	**1,116,293**	1,105,526	1,034,057
Operating Expenses			
Electricity purchased and fuel used in generation	**321,524**	296,009	225,607
Natural gas purchased	**244,060**	270,647	228,937
Other operating expenses	**172,245**	182,285	205,249
Maintenance	**49,441**	49,942	55,709
Depreciation and amortization	**71,285**	72,858	89,822
Other taxes	**69,630**	65,396	74,912
Gain on sale of generation assets	-	-	(340,739)
Deferral of asset sale gain	-	-	228,785
Total Operating Expenses	**928,185**	937,137	768,282
Operating Income	**188,108**	168,389	265,775
Other (Income)	**(4,382)**	(4,391)	(11,717)
Other Deductions	**1,232**	2,684	(983)
Interest Charges, Net	**56,203**	56,445	54,831
Income Before Income Taxes	**135,055**	113,651	223,644
Income Taxes	**52,760**	34,662	153,327
Net Income	**82,295**	78,989	70,317
Preferred Stock Dividends	-	-	1,789
Earnings Available for Common Stock	**$82,295**	$78,989	$68,528

The notes on pages 106 through 125 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2006	2005
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$5,902**	$28,752
Investments available for sale	-	53,325
Accounts receivable and unbilled revenues, net	**213,142**	193,807
Fuel and natural gas in storage, at average cost	**50,021**	57,434
Materials and supplies, at average cost	**13,533**	13,204
Deferred income taxes	**14,663**	-
Derivative assets	**21**	21,597
Broker margin accounts	**31,359**	-
Prepayments and other current assets	**36,760**	27,047
Total Current Assets	**365,401**	395,166
Utility Plant, at Original Cost		

Electric	**1,298,609**	1,258,330
Natural gas	**584,857**	572,943
Common	**202,276**	199,015
	2,085,742	2,030,288
Less accumulated depreciation	**619,262**	583,557
Net Utility Plant in Service	**1,466,480**	1,446,731
Construction work in progress	**80,291**	18,748
Total Utility Plant	**1,546,771**	1,465,479
Other Property and Investments	**11,271**	11,634
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**174,307**	183,039
Deferred income taxes	**-**	12,007
Unfunded future income taxes	**13,154**	-
Environmental remediation costs	**25,988**	25,013
Unamortized loss on debt reacquisitions	**11,071**	14,336
Nonutility generator termination agreement	**73,021**	82,243
Natural gas hedges	**22,724**	-
Other	**123,720**	127,867
Total regulatory assets	**443,985**	444,505
Other assets		
Prepaid pension benefits	**97,180**	48,368
Other	**15,782**	17,121
Total other assets	**112,962**	65,489
Total Regulatory and Other Assets	**556,947**	509,994
Total Assets	**$2,480,390**	$2,382,273

The notes on pages 106 through 125 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	**2006**	**2005**
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable	**$20,890**	-
Accounts payable and accrued liabilities	**135,863**	$123,145
Interest accrued	**9,589**	9,830
Taxes accrued	**12,711**	16,438
Unfunded future income taxes	**3,987**	-
Deferred income taxes	**-**	698
Derivative liabilities	**22,542**	1,562
Other	**44,947**	36,396
Total Current Liabilities	**250,529**	188,069
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	**189,035**	182,346
Deferred income taxes	**6,541**	-

Unfunded future income taxes	-	89,104
Gain on sale of generation assets	**118,031**	111,262
Pension benefit	**33,519**	-
Natural gas hedges	-	21,969
Other	**39,096**	51,015
Total regulatory liabilities	**386,222**	455,696
Other liabilities		
Deferred income taxes	**237,440**	167,785
Nuclear waste disposal	**113,763**	108,570
Other postretirement benefits	**74,583**	80,045
Asset retirement obligation	**21,251**	5,805
Environmental remediation costs	**37,523**	36,506
Other	**58,464**	59,341
Total other liabilities	**543,024**	458,052
Total Regulatory and Other Liabilities	**929,246**	913,748
Long-term debt	**698,025**	697,951
Total Liabilities	**1,877,800**	1,799,768
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000 shares authorized, 38,886 shares outstanding at December 31, 2006 and 2005)	**194,429**	194,429
Capital in excess of par value	**483,662**	483,252
Retained earnings	**50,844**	28,549
Accumulated other comprehensive loss	**(9,107)**	(6,487)
Treasury stock, at cost (4,379 shares at December 31, 2006 and 2005)	**(117,238)**	(117,238)
Total Common Stock Equity	**602,590**	582,505
Total Liabilities and Stockholder's Equity	**$2,480,390**	$2,382,273

The notes on pages 105 through 125 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Statements of Cash Flows

Year Ended December 31,	2006	2005	2004
(Thousands)			
Operating Activities			
Net income	**$82,295**	$78,989	$70,317
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	**136,019**	140,099	166,468
Income taxes and investment tax credits deferred, net	**45,114**	(3,607)	37,945
Income taxes related to gain on sale of generation assets	-	-	111,954
Gain on sale of generation assets	-	-	(340,739)
Deferral of asset sale gain	-	-	228,785
Pension income	**(15,293)**	(10,471)	(21,372)
Changes in current operating assets and liabilities			
Accounts receivable and unbilled revenues, net	**(18,943)**	(38,243)	4,655
Inventory	**7,084**	(23,598)	(10,479)
Prepayments and other current assets	**(41,073)**	(8,521)	(4,839)

Accounts payable and accrued liabilities	**5,164**	60,297	6,168
Customer refund	**(15,426)**	(25,329)	(58,219)
Interest accrued	**(240)**	535	(2,246)
Taxes accrued	**(1,176)**	(1,235)	(74,776)
Other current liabilities	**(15,071)**	(19,816)	(1,548)
Changes in other assets			
Nuclear plant dispute settlement	**(33,655)**	(125)	(141)
Other	**(6,247)**	(12,639)	(14,786)
Changes in other liabilities			
Generation related ASGA charges	**(55,420)**	(25,798)	(31,064)
Other	**7,262**	24,890	(7,627)
Net Cash Provided by Operating Activities	**80,394**	135,428	58,456
Investing Activities			
Sale of generation assets	**-**	-	453,678
Excess decommissioning funds retained	**-**	-	76,593
Utility plant additions	**(141,032)**	(55,450)	(81,717)
Nuclear generating plant decommissioning fund	**-**	-	(8,560)
Maturities of current investments available for sale	**372,950**	553,835	561,050
Purchases of current investments available for sale	**(319,625)**	(547,735)	(620,475)
Investments	**(166)**	(346)	-
Net Cash (Used in) Provided by Investing Activities	**(87,873)**	(49,696)	380,569
Financing Activities			
Repayments of first mortgage bonds and preferred stock, including net premiums	**-**	-	(201,000)
Notes payable three months or less, net	**20,890**	-	-
Book overdraft	**(1,261)**	1,186	3,296
Liquidating dividend	**-**	-	(75,000)
Dividends on common and preferred stock	**(35,000)**	(70,000)	(171,789)
Net Cash Used in Financing Activities	**(15,371)**	(68,814)	(444,493)
Net Increase (Decrease) in Cash and Cash Equivalents	**(22,850)**	16,918	(5,468)
Cash and Cash Equivalents, Beginning of Year	**28,752**	11,834	17,302
Cash and Cash Equivalents, End of Year	**$5,902**	$28,752	$11,834

The notes on pages 106 through 125 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Statements of Changes in Common Stock Equity

(Thousands)	Common Stock Outstanding $5 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accur Compre
Balance, January 1, 2004	38,886	$194,429	$556,190	$121,032	
Net income				70,317	
Other comprehensive income, net of tax					
Comprehensive income					
Liquidating dividend			(75,000)		
Equity contribution from parent			563		
Dividends declared					

Preferred stock				(1,789)	
Common stock				(170,000)	
Balance, December 31, 2004	38,886	194,429	481,753	19,560	
Net income				78,989	
Other comprehensive income, net of tax					
Comprehensive income					
Equity contribution from parent			1,499		
Common stock dividends declared				(70,000)	
Balance, December 31, 2005	38,886	194,429	483,252	28,549	
Net income				82,295	
Other comprehensive income, net of tax					
Comprehensive income					
Adjustment to initially apply Statement 158 for nonqualified plans					
Equity contribution from parent			410		
Common stock dividends declared				(60,000)	
Balance, December 31, 2006	38,886	$194,429	$483,662	$50,844	$

The notes on pages 106 through 125 are an integral part of the financial statements.

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 1. Significant Accounting Policies

Background: RG&E is primarily engaged in electricity generation, transmission and distribution operations and natural gas transportation and distribution operations in western New York. RG&E is an operating utility subsidiary of RGS Energy. Effective June 28, 2002, RGS Energy became a wholly-owned subsidiary of Energy East Corporation. The acquisition was accounted for under the purchase method of accounting. RGS Energy did not push goodwill down to RG&E.

Accounts receivable: Accounts receivable include unbilled revenues of $50 million at December 31, 2006, and $54 million at December 31, 2005, and are shown net of an allowance for doubtful accounts of $11 million at December 31, 2006, and $13 million at December 31, 2005. Accounts receivable balances do not bear interest although late fees may be assessed. Bad debt expense was $8 million in 2006, $4 million in 2005 and $5 million in 2004.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

The allowance for doubtful accounts is RG&E's best estimate of the amount of probable credit losses in its existing accounts receivable, determined based on experience for each service region and operating segment and other economic data. Each month RG&E reviews its allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and reviews all other balances on a pooled basis by age and type of receivable. When RG&E believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors such as economic conditions and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Asset retirement obligation and FIN 47: In accordance with FASB Statement 143 and FIN 47, RG&E records the fair value of the liability for an asset retirement obligation and/or a conditional asset retirement obligation in the period in which it is incurred and capitalizes the cost by increasing the carrying amount of the related long-lived asset. RG&E adjusts the liability to its present value periodically over time, and depreciates the capitalized cost over the useful life of the related asset. Upon settlement RG&E will either settle the obligation at its recorded amount or incur a gain or a loss. RG&E defers any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

FIN 47 clarifies that the term conditional asset retirement obligation as used in Statement 143 refers to an entity's 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. FIN 47 requires that if an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional asset retirement obligation, it must recognize that liability at the time the liability is incurred. RG&E began applying FIN 47 as of December 31, 2005. RG&E's application of FIN 47 did not have a material effect on its financial position, and there was no effect on its results of operations or cash flows.

Notes to Financial Statements

Rochester Gas and Electric Corporation

RG&E's asset retirement obligation (ARO) including its estimated conditional asset retirement obligation at December 31 was $21 million for 2006 and $6 million for 2005. The ARO primarily consists of obligations related to removal or retirement of: asbestos, polycholorinated biphenyl (PCB) contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with the AROs are generation property, distribution property and other property. RG&E's pro forma conditional asset retirement obligation was $3 million at December 31, 2004.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2006 and 2005. The increase for 2006 is primarily for removal of asbestos from generating stations and the increase for 2005 is primarily for initially applying FIN 47.

Year ended December 31,	2006	2005
(Thousands)		
ARO, beginning of year	**$5,805**	$1,907
Liabilities incurred during the year	**12,249**	3,915

Liabilities settled during the year	**(517)**	(143)
Accretion expense	**280**	126
Revisions in estimated cash flows	**3,434**	-
ARO, end of year	**$21,251**	$5,805

RG&E has AROs for which it has not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including: the removal of hydro dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Statements of cash flows: RG&E considers all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Statement 143 provides that if the requirements of Statement 71 are met, a regulatory liability should be recognized for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. RG&E classifies those amounts as accrued removal obligations.

Supplemental Disclosure of Cash Flows Information	**2006**	**2005**	**2004**
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	**$42,370**	$41,261	$49,283
Income taxes, net of benefits received	**$9,326**	$37,742	$76,053

The amount of capitalized interest was $1.5 million in 2006 and $0.5 million in 2005 and 2004.

Decommissioning expense: Other operating expenses for 2004 include nuclear decommissioning expense accruals. As a result of the sale of Ginna in June 2004 RG&E no longer has a decommissioning obligation and will not incur additional decommissioning expense.

-

Notes to Financial Statements

Rochester Gas and Electric Corporation

Depreciation and amortization: RG&E determines depreciation expense using the straight-line method. The average service lives of certain classifications of property are: transmission property - 58 years, distribution property - 53 years, generation property - 39 years and other property - 25 years. RG&E determines depreciation expense for the majority of its generation property using remaining service life rates, which include estimated cost of removal, based on operating license or anticipated closing dates. The remaining service lives of generation property range from 1 years for its coal station to 31 years for its hydroelectric stations. RG&E's depreciation accruals were equivalent to 3.2% of average depreciable property for 2006, 3.4% for 2005 and 3.6% for 2004.

RG&E charges repairs and minor replacements to operating expense, and capitalizes renewals and betterments, including certain indirect costs. It charges the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Estimates: Preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

FIN 48: In July 2006 the FASB released FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with Statement 109 by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or to be taken in a tax return. The evaluation of a tax position is a two-step process. The first step is for an entity to determine if it is more likely than not that a tax position will be sustained upon examination. The second step involves measuring the amount of tax benefit to be recognized in the financial statements based on the largest amount of benefit that meets the prescribed recognition threshold. The difference between the amounts based on that position and the position taken in a tax return is generally recorded as a liability. FIN 48 is effective for fiscal years beginning after December 15, 2006. Upon adoption of FIN 48, the cumulative effect of applying the provisions of FIN 48 must be reported as an adjustment to the opening balance of retained earnings for that fiscal year. RG&E adopted FIN 48 effective January 1, 2007. While RG&E is still in the process of measuring the effect of the adoption, it estimates that the adoption will not have a material effect on its results of operations or financial position.

Investments available for sale: RG&E held no current investments at December 31, 2006 and $53 million at December 31, 2005, which consisted of auction rate securities classified as available-for-sale. RG&E's investments in those securities are recorded at cost, which approximates fair market value due to their variable interest rates, which typically reset every 7 to 35 days. Despite the long-term nature of their stated contractual maturities, RG&E has the ability to quickly liquidate such securities. As a result, RG&E has no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from its current investments. All income generated from such current investments is recorded as interest income.

Notes to Financial Statements

Rochester Gas and Electric Corporation

Other (Income) and Other Deductions:

Year Ended December 31,	2006	2005	2004
(Thousands)			
Interest and dividend income	**$(2,853)**	$(3,574)	$(3,653)
2004 RG&E Electric and Natural Gas Rate Agreement	**-**	-	(6,117)
Miscellaneous	**(1,529)**	(817)	(1,947)
Total other (income)	**$(4,382)**	$(4,391)	$(11,717)
Miscellaneous	**$1,232**	$2,684	$(983)
Total other deductions	**$1,232**	$2,684	$(983)

Regulatory assets and liabilities: Pursuant to Statement 71, RG&E capitalizes, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. RG&E also records, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

RG&E amortizes its various regulatory assets and regulatory liabilities as follows: Unfunded future income taxes and deferred income taxes as the related temporary differences reverse; Nuclear plant obligations, other regulatory assets and other regulatory liabilities over various periods in accordance with RG&E's current rate plans.

At December 31, 2006 and 2005, RG&E's Other regulatory assets and liabilities consisted of:

	2006	2005
(Thousands)		
Loss on sale of Oswego generating unit	**$41,895**	$48,371
Deferred ice storm costs	**28,811**	32,014
Asset retirement obligation	**16,668**	3,541
Merger costs	**12,406**	24,393
Other	**23,940**	19,548
Total other regulatory assets	**$123,720**	$127,867
Pension	**$6,527**	$2,719
Nuclear fuel disposal	**5,729**	5,555
Overcollection of Gross Receipts Tax	**5,506**	7,860
Accrued earnings sharing	**-**	19,086
Other	**21,334**	15,795
Total other regulatory liabilities	**$39,096**	$51,015

-

Notes to Financial Statements

Rochester Gas and Electric Corporation

Related party transactions: Utility Shared Services Corporation and Energy East Management Corporation provide various administrative and management services to Energy East's operating utilities, including RG&E, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. The cost for services provided to RG&E by Utility Shared Services Corporation and Energy East Management Corporation was approximately $23 million in 2006, $22 million in 2005 and $26 million in 2004.

Revenue recognition: RG&E recognizes revenues upon delivery of energy and energy-related products and services to its customers.

RG&E enters into power purchase and sales transactions with the NYISO. When RG&E sells electricity from owned generation to the NYISO, and subsequently repurchases electricity from the NYISO to serve its customers, RG&E records the transactions on a net basis in its statements of income.

***Risk management*:** The financial instruments RG&E holds or issues are not for trading or speculative purposes.

RG&E uses derivative instruments to mitigate risk resulting from interest rate changes on anticipated future financings and amortizes amounts paid or received under those instruments to interest expense over the life of the corresponding financing.

RG&E faces risks related to counterparty performance on hedging contracts due to counterparty credit default. RG&E, in conjunction with Energy East, has developed a matrix of unsecured credit thresholds that are dependent on a counterparty's Moody's or S&P credit rating. When Energy East's exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or RG&E will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

RG&E uses electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity. It includes the cost or benefit of those contracts in the amount expensed for electricity purchased when the electricity is sold.

RG&E has a purchased gas adjustment clause that allows it to recover through rates any changes in the market price of purchased natural gas, substantially eliminating its exposure to natural gas price risk. RG&E uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. It includes the cost or benefit of natural gas futures and forwards in the commodity cost when the related sales commitments are fulfilled.

RG&E recognizes the fair value of its financial electricity contracts, natural gas hedge contracts and interest rate derivative instruments as current derivative assets or liabilities, other assets or other liabilities. RG&E's financial electricity contracts and interest rate derivative instruments are designated as cash flow hedging instruments. RG&E records changes in the fair value of the cash flow hedging instruments in other comprehensive income, to the extent they are considered effective, until the underlying transaction occurs. RG&E records the ineffective portion of any

change in fair value of cash flow hedges to the income statement as either Other (Income) or Other Deductions as appropriate. RG&E records changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities. At December 31, 2006, RG&E had $1 million of derivative assets all of which were noncurrent and $32 million of derivative liabilities, of which $23 million were current. At December 31, 2005, it had $22 million of derivative assets, all of which were current, and $4 million of derivative liabilities, of which $3 million were noncurrent.

RG&E uses quoted market prices to determine the fair value of derivatives and adjust for volatility and inflation when the period of the derivative exceeds the period for which market prices are readily available.

As of December 31, 2006, the maximum length of time over which RG&E has hedged its exposure to the variability in future cash flows for forecasted transactions is 16 months.

RG&E has commodity purchase and sales contracts for both capacity and energy that have been designated and qualify for the normal purchases and normal sales exception in Statement 133, as amended.

Statement 157: In September 2006 the FASB issued Statement 157. Changes from current practice that will result from the application of Statement 157 relate to the definition of fair value, the methods used to measure fair value, and expanded disclosures about fair value measurements. Statement 157 applies under other accounting pronouncements that require or permit fair value measurements in which the FASB previously concluded that fair value is the relevant measurement attribute. It does not require any new fair value measurements, but may change current practice for some entities. Statement 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged. The provisions are to be applied prospectively, with certain exceptions. A cumulative-effect adjustment to retained earnings is required for application to certain financial instruments. RG&E will adopt Statement 157 effective January 1, 2008. RG&E is currently assessing the effect Statement 157 would have on its results of operations, financial position and cash flows.

Statement 158: In September 2006 the FASB issued Statement 158, which amends FASB Statements No. 87, 88, 106 and 132(R), and requires an employer to:

- recognize the overfunded or underfunded status of defined benefit pension and/or other postretirement plans as an asset or liability in its balance sheet;
- recognize changes in the funded status of such plans in the year in which the changes occur through comprehensive income;
- measure the funded status of a plan as of the date of its year-end balance sheet, and
- disclose in the notes to the annual financial statements certain effects that the delayed recognition of the gains or losses, prior service costs or credits and transition asset or obligation are expected to have on net periodic benefit cost for the next fiscal year.

The funded status of a benefit plan is measured as the difference between plan assets at fair value and the benefit obligation, which is the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for any other postretirement plan. As required by Statement 158, gains or losses and prior service costs or credits that arise during the period

but are not recognized as components of net periodic benefit cost pursuant to Statement 87 or

Statement 106 are recognized as a component of other comprehensive income, net of tax. Gains or losses, prior service costs or credits and the transition asset or obligation remaining from the initial application of Statements 87 and 106 that are recognized in accumulated other comprehensive income are adjusted as they are subsequently recognized as components of net periodic benefit cost pursuant to the recognition and amortization provisions of those Statements. However, RG&E is a rate-regulated entity that meets the criteria to apply Statement 71. Based on its assessments of the facts and circumstances applicable to RG&E's jurisdiction and regulatory environment, RG&E has determined that it is allowed to defer as regulatory assets or regulatory liabilities the above indicated items. Other entities that are not rate-regulated would recognize those items as a component of other comprehensive income and/or include them in accumulated other comprehensive income.

RG&E initially applied the recognition and disclosure provisions of Statement 158 as of December 31, 2006, with no material effect on its financial position and no effect on its results of operation or cash flows. Retrospective application of the recognition provisions and measurement provisions is not permitted. RG&E measures its pension and other postretirement plan assets and benefit obligations as of the date of its fiscal year-end balance sheet and therefore has no need to change its measurement date. The incremental effect of applying Statement 158 for RG&E's qualified plans on individual line items in its balance sheet as of December 31, 2006, is:

	Before Application of Statement 158	Adjustments	After Application of Statement 158
(Thousands)			
Other Assets			
Prepaid pension benefits	$63,661	$33,519	$97,180
Total other assets	79,443	33,519	112,962
Total Assets	$2,446,871	$33,519	$2,480,390
Current Liabilities			
Deferred income taxes	$2,294	$(2,294)	-
Other current liabilities	39,194	5,753	$44,947
Total current liabilities	247,070	3,459	250,529
Regulatory liabilities			
Deferred income taxes	20,375	(13,834)	6,541
Pension benefit	-	33,519	33,519
Other	37,921	1,175	39,096
Total regulatory liabilities	365,362	20,860	386,222
Other liabilities			
Deferred income taxes	221,312	16,128	237,440
Other postretirement benefits	81,511	(6,928)	74,583
Total other liabilities	533,824	9,200	543,024
Total Regulatory and Other Liabilities	899,186	30,060	929,246
Total Liabilities	1,844,281	33,519	1,877,800
Total Liabilities and Stockholder's Equity	$2,446,871	$33,519	$2,480,390

Taxes: RG&E computes its income tax provision on a separate return method. The determination and allocation of RG&E's income tax provision and its components are outlined and agreed to in its tax sharing agreement with Energy East.

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. RG&E amortizes ITCs over the estimated lives of the related assets.

RG&E accounts for sales tax collected from customers and remitted to taxing authorities on a net basis.

Energy East revised its Income Tax Allocation Agreement (Agreement) in 2006. The revised Agreement, which applies to income tax returns after 2004, and is accounted for at the time of the filing of the income tax returns in the subsequent year, eliminates the push-down requirements of PUHCA and better aligns the allocation of income taxes with the Cost of Service "stand alone" approach used in each of our regulated entities' rate structures.

If the revised agreement had been in place in 2004 and 2005, RG&E's income taxes would have been $0.1 million higher for 2004 and $5.7 million higher for 2005.

Note 2. Sale of Ginna

In June 2004, after receiving all regulatory approvals, RG&E sold Ginna to CGG. RG&E received at closing $429 million and received in September 2004 an additional $25 million for post-closing adjustments. RG&E's 2004 statement of income reflects a gain on the sale of Ginna of $341 million. The deferral of the asset sale gain, after related taxes of $112 million, is $229 million.

RG&E's Electric Rate Agreement resolved all regulatory and ratemaking aspects related to the sale of Ginna, including providing for an ASGA of $378 million after the post-closing adjustments, and addressing the disposition of the asset sale gain. Upon closing of the sale of Ginna, RG&E transferred $201 million of decommissioning funds to CGG, which has taken responsibility for all future decommissioning funding. RG&E retained $77 million in excess decommissioning funds, which was credited to its customers as part of the ASGA.

Note 3. Other Intangible Assets

RG&E amortizes intangible assets with finite lives (amortized intangible assets) and reviews them for impairment. RG&E has no goodwill or intangible assets with indefinite lives. RG&E's amortized intangible assets consist of water rights and had a gross carrying amount of $3 million and accumulated amortization of about $2 million at December 31, 2006 and 2005. Estimated amortization expense for intangible assets is $78 thousand for each of the next five years, 2007 through 2011.

Note 4. Income Taxes

Year Ended December 31,	2006	2005	2004
(Thousands)			
Current			
Federal	**$9,942**	$32,337	$72,446
State	**(2,297)**	7,520	(5,924)
Current taxes charged to expense	**7,645**	39,857	66,522
Deferred			
Federal	**34,798**	(5,631)	75,231
State	**11,505**	1,624	17,702
Deferred taxes charged to expense	**46,303**	(4,007)	92,933
ITC adjustment	**(1,188)**	(1,188)	(6,128)
Total	**$52,760**	$34,662	$153,327

RG&E's tax expense differed from the expense at the statutory rate of 35% due to the following:

Year Ended December 31,	2006	2005	2004
(Thousands)			
Tax expense at statutory rate	**$47,269**	$39,778	$78,276
Depreciation and amortization not normalized	**500**	1,434	(4,238)
ITC amortization	**(1,188)**	(1,188)	(6,128)
State taxes, net of federal benefit	**5,985**	5,944	7,656
Cost of removal not normalized	**(1,546)**	(2,066)	(2,623)
Audit settlement, reserve for disputed items	**2,570**	(208)	(636)
ASGA, Ginna	-	-	80,075
Consolidated federal tax allocation	-	(5,568)	(149)
Other, net	**(830)**	(3,464)	1,094
Total	**$52,760**	$34,662	$153,327

RG&E's effective tax rate was 39% in 2006, 31% in 2005 and 69% in 2004. RG&E's tax expense for 2005 differed from the expense at the statutory rate primarily due to a decrease in taxes recorded in 2005 related to the allocation of the 2004 consolidated current income tax provision pursuant to the tax sharing agreement with Energy East. RG&E's effective tax rate differed from the statutory rate in 2004 primarily due to the implication of the sale of Ginna.

At December 31, 2006 and 2005, RG&E's deferred tax assets and liabilities consisted of:

	2006	2005
(Thousands)		
Current Deferred Income Tax Assets (Liabilities)		
Derivative assets	**$8,980**	$(7,989)
Other	**5,683**	7,291

Total Current Deferred Income Tax Assets (Liabilities)	**$14,663**	$(698)
Noncurrent Deferred Income Tax Liabilities		
Depreciation	**$239,237**	$203,188
Unfunded future income taxes	**2,222**	20,341
Accumulated deferred ITC	**6,797**	7,985
Deferred (gain) loss on sale of generation assets	**(31,620)**	(49,200)
Statement 106 postretirement benefits	**(27,957)**	(31,632)
Pension	**22,177**	29,882
Derivative liability	**(5,852)**	(9,734)
Other	**38,977**	(15,052)
Total Noncurrent Deferred Income Tax Liabilities	**243,981**	155,778
Less amounts classified as regulatory liabilities		
Deferred income taxes	**6,541**	(12,007)
Noncurrent Deferred Income Tax Liabilities	**$237,440**	$167,785
Deferred tax assets	**$80,092**	$112,909
Deferred tax liabilities	**309,410**	269,385
Net Accumulated Deferred Income Taxes	**$229,318**	$156,476

RG&E has no federal or state tax credit or loss carryforwards, and no valuation allowances.

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 5. Long-term Debt

At December 31, 2006 and 2005, RG&E's long-term debt was:

	Interest Rates	Maturity	2006	2005
			(Thousands)	
First mortgage bonds[(1)]				
Series B	5.84%	2008	**$50,000**	$50,000
Series B	7.60%	2009	**100,000**	100,000
Series TT	6.95%	2011	**161,000**	161,000
Series UU	6.65%	2032	**125,000**	125,000
PCN 2004 Series A	3.60%	2032	**10,500**	10,500
PCN 2004 Series B	3.85%	2032	**50,000**	50,000
Series VV	6.375%	2033	**75,000**	75,000
Total first mortgage bonds			**571,500**	571,500
Unsecured pollution control notes, fixed				
1998 Series A	5.95%	2033	**25,500**	25,500
Unsecured pollution control notes, variable				
1997 Series A	3.45%	2032	**34,000**	34,000
1997 Series B	3.50%	2032	**34,000**	34,000
1997 Series C	3.38%	2032	**33,900**	33,900

Total unsecured pollution control notes, variable	**101,900**	101,900
Unamortized discount on debt	**(875)**	(949)
Total	**$698,025**	$697,951

(1) RG&E's first mortgage bonds are secured by a first mortgage lien on substantially all of its properties. RG&E has no other secured indebtedness. None of RG&E's other debt obligations are guaranteed or secured by any of its affiliates.

At December 31, 2006, long-term debt, including sinking fund obligations (in thousands), that will become due during the next five years is:

2007	2008	2009	2010	2011
-	$50,000	$100,000	-	$161,000

Cross-default Provisions: RG&E has a provision in a participation agreement relating to certain series of pollution control bonds, which provides that default by RG&E with respect to bonds issued under its first mortgage indenture will be considered a default under the participation agreement.

Note 6. Bank Loans and Other Borrowings

RG&E is a joint borrower, along with NYSEG, CNG, SCG, CMP and Berkshire Gas, in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. The facility expires in 2011 and requires fees on undrawn borrowing capacity. RG&E has no liability for any other joint borrower. RG&E's maximum borrowing limit under the facility is $100 million. RG&E pays a facility fee of 10 basis points annually on its revolver sublimit.

RG&E uses drawings on its credit facility to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. RG&E had $21 million of short-term debt outstanding at December 31, 2006 and no short-term debt outstanding at December 31, 2005. The weighted average interest rate on short-term debt was 8.25% at December 31, 2006.

In the revolving credit facility, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of indebtedness to total capitalization, RG&E excludes from net worth the balance of 'Accumulated other comprehensive income (loss)' as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain.

Continued unremedied failure to observe those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. At December 31, 2006, RG&E's ratio of total indebtedness to total capitalization was 0.54 to 1.00. RG&E is not in default, and no condition exists that is likely to create a default, under the facility.

Note 7. Preferred Stock Redeemable Solely at the Option of RG&E

RG&E redeemed the following amounts of preferred stock, all at a premium, on May 5, 2004: $12 million of 4% Series F (120,000 shares), $8 million of 4.10% Series H (80,000 shares), $6 million of 4.75% Series I (60,000 shares), $5 million of 4.10% Series J (50,000 shares), $6 million of 4.95% Series K (60,000 shares) and $10 million of 4.55% Series M (100,000 shares).

At December 31, 2006, RG&E had 2,000,000 shares of $100 par value cumulative preferred stock, 4,000,000 shares of $25 par value cumulative preferred stock and 5,000,000 shares of $1 par value preference stock authorized but unissued.

Note 8. Commitments and Contingencies

***Capital spending*:** We have commitments in connection with our capital spending program. We plan to invest amounts in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. We expect that approximately one-half of our capital spending will be paid for with internally generated funds and the remainder through the issuance of debt securities. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, increased transmission capacity, necessary improvements to existing facilities, the installation of an advanced metering infrastructure and compliance with environmental requirements and governmental mandates.

Nuclear entitlement power purchase contracts: In connection with RG&E's sales of nuclear generating assets in 2004 and 2001, RG&E entered into two entitlement contracts under which it purchases electricity at a fixed contract price. RG&E expensed approximately $200 million for nuclear entitlement power in 2006, $203 million in 2005 and $139 million in 2004. RG&E estimates that its nuclear entitlement power purchases will be $222 million in 2007, $226 million in 2008, $230 million in 2009, $245 million in 2010, and $219 million in 2011.

***NYISO billing adjustment*:** The NYISO frequently bills market participants on a retroactive basis when it determines that billing adjustments are necessary. Such retroactive billings can cover several months or years and cannot be reasonably estimated. RG&E records transmission or supply revenue or expense, as appropriate, when revised amounts are available. RG&E has developed an accrual process that incorporates available information about retroactive NYISO billing adjustments as provided to all market participants. However, on an ongoing basis, RG&E cannot fully predict either the magnitude or the direction of any