ENERGY EAST CORP
Form 10-K
March 01, 2007

Quick Links/Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2006**

OR

_

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission file number	Exact name of Registrant as specified in its charter, State of incorporation, Address and Telephone number	IRS Employer Identification No.
1-14766	Energy East Corporation (Incorporated in New York) 52 Farm View Drive New Gloucester, Maine 04260-5116 (207) 688-6300 **www.energyeast.com**	14-1798693
1-672	Rochester Gas and Electric Corporation (Incorporated in New York) 89 East Avenue Rochester, New York 14649 (800) 743-2110	

16-0612110

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
Energy East Corporation	Common Stock (Par Value $.01)	New York Stock Exchange
Rochester Gas and Electric Corporation	6.65% Series UU First Mortgage Bonds, due 2032	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Not applicable

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
Energy East Corporation	X	
Rochester Gas and Electric Corporation	X	

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

Registrant	Yes	No
Energy East Corporation		X
Rochester Gas and Electric Corporation		X

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No _____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part

III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a nonaccelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large accelerated filer	Accelerated filer	Non-accelerated filer
Energy East Corporation	X		
Rochester Gas and Electric Corporation			X

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Registrant	Yes	No
Energy East Corporation		X
Rochester Gas and Electric Corporation		X

The aggregate market value of the common stock held by nonaffiliates of Energy East Corporation as of June 30, 2006, the last business day of Energy East's most recently completed second fiscal quarter, was $3.5 billion, based on the closing sale price as reported on the New York Stock Exchange.

As of February 15, 2007, shares of common stock outstanding for each registrant were:

Registrant	Description	Shares
Energy East Corporation	Par value $.01 per share	147,836,184
Rochester Gas and Electric Corporation	Par value $5 per share	34,506,513[(1)]

(1)

All shares are owned by RGS Energy Group, Inc., a wholly-owned subsidiary of Energy East Corporation.

DOCUMENTS INCORPORATED BY REFERENCE

Document	10-K Part
Energy East Corporation has incorporated by reference certain portions of its Proxy Statement, which will be filed with the Commission on or before April 30, 2007.	III

This combined Form 10-K is separately filed by **Energy East Corporation** and **Rochester Gas and Electric Corporation**. Information contained herein relating to either registrant is filed by such registrant on its own behalf. Neither registrant makes any representation as to information relating to the other registrant.

Rochester Gas and Electric Corporation

meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K in the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

Table of Contents

Glossary of Energy East Companies

Abbreviations for the Energy East companies mentioned in this report:

Berkshire Energy

Berkshire Energy Resources is the parent of The Berkshire Gas Company.

Berkshire Gas The Berkshire Gas Company is a regulated utility primarily engaged in the distribution of natural gas in western Massachusetts.

Cayuga Energy Cayuga Energy, Inc. owns interests in electric generation facilities that sell power in the NYISO and PJM Interconnection wholesale markets at times of high demand.

CMP Central Maine Power Company is a regulated utility primarily engaged in transmitting and distributing electricity generated by others to retail customers in Maine.

CMP Group CMP Group, Inc. is the parent of Central Maine Power Company (CMP).

CNE Connecticut Energy Corporation is the parent of The Southern Connecticut Gas Company (SCG).

CNG Connecticut Natural Gas Corporation is a regulated utility primarily engaged in the retail distribution of natural gas in Connecticut.

CTG Resources CTG Resources, Inc. is the parent of Connecticut Natural Gas Corporation (CNG).

Energetix Energetix, Inc. markets electric and natural gas services in upstate New York.

Energy East, the company, we, our or **us**
Energy East Corporation is the parent company of RGS Energy Group, Inc., Connecticut Energy Corporation, CMP Group, CTG Resources, Berkshire Energy Resources, The Energy Network, Inc. and Energy East Enterprises, Inc.

MNG Maine Natural Gas Corporation is a small natural gas delivery company in the state of Maine.

NYSEG New York State Electric & Gas Corporation is a regulated utility primarily engaged in purchasing and delivering electricity

RG&E

Rochester Gas and Electric Corporation is a regulated utility primarily engaged in generating, purchasing and delivering electricity and purchasing and delivering natural gas in an area centered around the city of Rochester, New York.

RGS Energy RGS Energy Group, Inc. is the parent of NYSEG and RG&E.

SCG The Southern Connecticut Gas Company is a regulated utility primarily engaged in the retail distribution of natural gas in Connecticut.

SGF South Glens Falls Energy, LLC operated a natural gas fired generating unit in New York.

TEN Cos. TEN Companies, Inc. owns and manages a district heating and cooling network in Hartford, Connecticut.

The Energy Network The Energy Network, Inc. owns and manages our non-regulated businesses.

and natural gas in the central, eastern and western parts of the state of New York.

Glossary of Terms

Abbreviations or acronyms frequently used in this report:

ALJ

Administrative Law Judge

APB 25 Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*

ARP 2000 Alternative Rate Plan 2000

ASGA Asset Sale Gain Account

Bechtel Bechtel Power Corporation

CGG Constellation Generation Group, LLC

Connecticut Yankee Connecticut Yankee Atomic Power Company

DOE United States Department of Energy

DPUC Connecticut Department of Public Utility Control

DSM demand side management

DTE Massachusetts Department of Telecommunications and Energy

Dth dekatherm

Electric Rate Agreement Electric portion of RG&E's 2004 Electric and Natural Gas Rate Agreements

EPA United States Environmental Protection Agency

EPS earnings per share

ESCO energy service company

FASB Financial Accounting Standards Board

FIN 47

FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*

FIN 48 FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*

Ginna Robert E. Ginna Nuclear Power Plant, a nuclear power plant sold by RG&E in June 2004

IRP Incentive Rate Plan

ISO-NE ISO New England Inc.

ITC investment tax credit

LICAP locational installed capacity (pricing mechanism in the New England market)

MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations

MPUC Maine Public Utilities Commission

MW, MWh megawatt, megawatt hour

Natural Gas Rate Agreement natural gas portion of RG&E's 2004 Electric and Natural Gas Rate Agreements

NRC United States Nuclear Regulatory Commission

NUG nonutility generator

NYISO New York Independent System Operator

NYPA New York Power Authority

NYPSC New York State Public

FERC Federal Energy Regulatory Commission

FIN 46(R) FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51*

Service Commission

NYSDEC New York State Department of Environmental Conservation

Glossary of Terms (Continued)

NYSERDA

New York State Energy Research and Development Authority

OCC The Office of Consumer Counsel in the State of Connecticut

OPEB other post-employment benefits

PJM Interconnection PJM Interconnection, LLC

ROE return on equity

RTO Regional Transmission Organization

Russell Station A coal-fired electric generation facility in Greece, New York

SAR stock appreciation right

SEC or the Commission United States Securities and Exchange Commission

SPDES State Pollutant Discharge Elimination System

Statement 71 Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*

Statement 87 Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions*

Statement 106 Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*

Statement 123

Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*

Statement 123(R) Statement of Financial Accounting Standards No. 123 (revised 2004), *Shared-Based Payment*

Statement 133 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*

Statement 143 Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*

Statement 157 Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*

Statement 158 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)*

TCC transmission congestion contract

VEBA voluntary employees' beneficiary association

Voice Your Choice RG&E's and NYSEG's electric commodity option programs

Yankee companies Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric

Power Company

Forward-looking Statements

The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. This Form 10-K contains certain forward-looking statements that are based upon management's current expectations and information that is currently available. Whenever used in this report, the words "estimate," "expect," "believe" "anticipate," or similar expressions are intended to identify such forward-looking statements.

In addition to the assumptions and other factors referred to specifically in connection with such statements, factors that involve risks and uncertainties that could cause actual results to differ materially from those contemplated in any forward-looking statements are discussed in Item 1A - Risk Factors and Item 7 - MD&A - Market Risk, and also include, among others:

- the deregulation and continued regulatory unbundling of a formerly vertically integrated utility industry,
- our ability to compete in the rapidly changing and competitive electric and/or natural gas utility markets,
- regulatory uncertainty and volatile energy supply prices,
- implementation of NYSEG's Electric Rate Order issued by the NYPSC that has been in effect since January 1, 2007,
- implementation of the Energy Policy Act of 2005,
- increased state and FERC regulation of, among other things, intercompany cost allocations,
- the operation of the NYISO and retroactive NYISO billing adjustments,
- the operation of ISO-NE as an RTO and CMP's continued participation in ISO-NE,
- our continued ability to recover NUG and other costs,
- changes in fuel supply or cost and the success of strategies to satisfy power requirements,
- our ability to expand our products and services including our energy infrastructure in the Northeast,
- the effect of commodity costs on customer usage and uncollectible expense,
- our ability to maintain enterprise-wide integration synergies,
- market risk from changes in value of financial or commodity instruments, derivative or nonderivative, caused by fluctuations in interest rates or commodity prices,
- the ability of third parties to continue to supply electricity and natural gas,
- our ability to obtain adequate and timely rate relief and/or the extension of current rate plans,
- the possible discontinuation or further modification of fixed-price supply programs in New York,
- nuclear decommissioning or environmental incidents,
- legal or administrative proceedings,
- changes in the cost or availability of capital,
- economic growth or contraction in the areas in which we do business,
- extreme weather-related events such as floods, hurricanes, ice storms or snow storms,
- weather variations affecting customer energy usage,
- authoritative accounting guidance,
- acts of terrorism,
- the effect of volatility in the equity and fixed income markets on the cost of pension and other

postretirement benefits,
- the inability of our internal control framework to provide absolute assurance that all incidents of fraud or error will be detected and prevented, and
- other considerations that may be disclosed from time to time in our publicly disseminated documents and filings.

We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

PART

I

Item 1. Business

General development of business

Energy East Corporation

: Energy East is a public utility holding company organized under the laws of the state of New York in 1997. Energy East is a super-regional energy services and delivery company with operations in New York, Connecticut, Massachusetts, Maine and New Hampshire. We conduct all of our operations through our wholly-owned subsidiaries including CNE, CMP Group, CTG Resources, Berkshire Energy, RGS Energy and The Energy Network.

CNE's

wholly-owned subsidiary, The Southern Connecticut Gas Company, is a regulated utility primarily engaged in the retail distribution of natural gas in Connecticut.

CMP Group's

wholly-owned subsidiary, Central Maine Power Company, is a regulated utility primarily engaged in transmitting and distributing electricity generated by others to retail customers in Maine.

CTG Resources'

wholly-owned subsidiary, Connecticut Natural Gas Corporation, is a regulated utility primarily engaged in the retail distribution of natural gas in Connecticut.

Berkshire Energy's

wholly-owned subsidiary, The Berkshire Gas Company, is a regulated utility primarily engaged in the distribution of natural gas in western Massachusetts.

RGS Energy's

wholly-owned subsidiaries are NYSEG and RG&E. NYSEG is a regulated utility primarily engaged in purchasing and delivering electricity and natural gas in the central, eastern and western parts of the state of New York. NYSEG sold a majority of its generation assets in 1999 and most of its remaining generation assets in 2001. RG&E is a regulated utility primarily engaged in generating, purchasing and delivering electricity and purchasing and delivering natural gas in an area centered around the city of Rochester, New York. RG&E sold its largest generating station, Ginna, in 2004.

The Energy Network's

wholly-owned subsidiaries include Cayuga Energy and NYSEG Solutions, Inc.

We created a support services company in 2004, Utility Shared Services Corporation, to consolidate support service functions for our largest regulated utilities. This consolidation allows us to optimize the efficiency of those services.

Rochester Gas and Electric Corporation

: RG&E is a public utility organized under the laws of the state of New York in 1904. RGS Energy was incorporated in 1998 in the state of New York and became the holding company for RG&E in August 1999. In June 2002, pursuant to a Plan of Merger, RGS Energy became our wholly-owned subsidiary and also became the holding company for NYSEG.

The following general developments have occurred in our businesses since January 1, 2006:

See Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas Delivery Rate Overview and Natural Gas Delivery Business Developments.

Regulation

We operate under the authority of the NYPSC in New York, the MPUC in Maine, the DPUC in Connecticut and the DTE in Massachusetts. We are also subject to regulation by the FERC. The FERC and state utility commissions have authority to regulate and monitor, among other things, intercompany cost allocations of holding company systems such as Energy East.

Financial information about segments

See Item 8 - Note 15 to our Consolidated Financial Statements and Note 13 to RG&E's Financial Statements.

Narrative description of business

Principal business

Our principal business consists of our regulated electricity transmission and distribution operations in upstate New York and Maine and our regulated natural gas transportation, storage and distribution operations in upstate New York, Connecticut, Maine and Massachusetts. We serve approximately two million electricity customers and one million natural gas customers. Our service territories reflect diversified economies, including high-technology firms, insurance, light industry, consumer goods manufacturing, pulp and paper, ship building, colleges and universities, agriculture, fishing and recreational facilities. Our operating revenues derived from regulated electricity sales were 58% in 2006, 56% in 2005 and 58% in 2004. Operating revenues derived from regulated natural gas sales were 32% in 2006, 34% in 2005 and 33% in 2004. No customer accounts for more than 5% of either electric or natural gas revenues.

NYSEG

conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 871,000 electricity and 256,000 natural gas customers in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport.

RG&E's

principal business consists of its regulated electricity generation, transmission and distribution operations and regulated natural gas transportation and distribution operations in western New York. RG&E generates electricity from one coal-fired plant, three gas turbine plants and several smaller hydroelectric stations. RG&E serves approximately 359,000 electricity and 296,000 natural gas customers in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban

area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. Approximately 66% of RG&E's operating revenues for 2006, 63% for 2005 and 64% for 2004 were derived from electricity sales, with the balance each year derived from natural gas sales. No customer accounts for more than 5% of either electric or natural gas revenues.

CMP

conducts regulated electricity transmission and distribution operations in Maine serving approximately 596,000 customers in its service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

SCG

conducts natural gas transportation and distribution operations in Connecticut serving approximately 176,000 customers in its service territory of approximately 560 square miles with a population of approximately 800,000. SCG's service territory extends along the southern Connecticut coast from Westport to Old Saybrook and includes the urban communities of Bridgeport and New Haven.

CNG

conducts natural gas transportation and distribution operations in Connecticut serving approximately 155,000 customers in its service territory of approximately 800 square miles with a population of approximately 800,000, principally in the greater Hartford-New Britain area and Greenwich.

Berkshire Gas

conducts natural gas distribution operations in western Massachusetts serving approximately 36,000 customers in its service territory of approximately 520 square miles with a population of approximately

220,000. Berkshire Gas' service territory includes the cities of Pittsfield and North Adams.

See Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas Delivery Rate Overview and Natural Gas Delivery Business Developments.

Other businesses

Our other businesses include retail energy marketing companies, a nonutility generating company, a FERC-regulated liquefied natural gas peaking plant, a natural gas delivery company, a propane air delivery company, telecommunications assets, a district heating and cooling system, and an energy consulting services company. We include their results of operations, financial condition and cash flows in our Other segment.

Energetix, Inc. and NYSEG Solutions, Inc.

market electricity and natural gas services throughout the state of New York. The revenues from these two companies accounted for approximately 9% of Energy East's total revenues in 2006, 10% in 2005 and 9% in 2004.

Cayuga Energy

owns electric generation facilities that sell power in the NYISO and PJM Interconnection wholesale markets at times of high demand.

CNE Energy Services Group, Inc.

has an interest in two small natural gas pipelines that serve power plants in Connecticut. CNE Energy Services Group has a long-term lease for a liquefied natural gas plant that serves the peaking gas markets in the Northeast and has an equity interest in an energy technology venture partnership.

Energy East Enterprises, Inc.

includes Maine Natural Gas, a small natural gas delivery company and New Hampshire Gas, Inc., a propane air delivery company.

MaineCom Services

owns fiber optic lines and provides telecommunications services in Maine.

TEN Companies, Inc.

owns and manages The Hartford Steam Company, a district heating and cooling network in Hartford, Connecticut, and owns an interest in the Iroquois Gas Transmission System.

The Union Water-Power Company

owns and manages real estate in Maine and New Hampshire and provides energy consulting services throughout New England.

Sources and availability of raw materials

Electric

See Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments and Commodity Price Risk and Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.

NYSEG satisfied the majority of its power requirements for 2006 through purchases under long-term contracts with NUGs, the New York Power Authority and Constellation Nuclear, and through generation from its several hydroelectric stations. NYSEG managed fluctuations in the cost of electricity

for its remaining power requirements through the use of electricity contracts, both physical and financial.

RG&E satisfied the majority of its power requirements for 2006 through purchases under long-term contracts with the New York Power Authority, Constellation Nuclear, and Ginna Nuclear Power Plant, LLC. A small portion, less than 20%, was satisfied from its generation facilities including coal, natural gas, hydroelectric and peaking. RG&E managed fluctuations in the cost of electricity for its remaining power requirements through the use of electricity contracts, both physical and financial.

Coal

- RG&E's 2007 coal requirements are expected to be approximately 400,000 tons. RG&E's coal supply portfolio contains both spot and term agreements with multiple suppliers. In 2006, 80% of RG&E's coal requirements was purchased under contract and 20% was purchased on the spot market. RG&E maintains a reserve supply of coal ranging from 30 to 60 days.

Under a Maine State Law adopted in 1997, CMP was mandated to sell its generation assets and relinquish its supply responsibility. CMP no longer owns generating assets but retains its power entitlements under long-term contracts with NUGs and a power purchase contract with

Entergy Nuclear Vermont Yankee, LLC. Since March of 2000 CMP has sold its power entitlement under auctions approved by the MPUC. By its orders issued in December 2004, December 2005 and January 2007, the MPUC approved CMP's sale of its entitlements for various periods ranging from one to three years, through February 28, 2010. CMP's retail electricity prices are set to provide recovery of the costs associated with its ongoing power entitlement obligations. CMP's revenues and purchased power costs would increase if it were required to be the standard-offer provider of electricity supply for retail customers. There would be no effect on CMP's net income in such an event, however, because CMP is ensured cost recovery through Maine state law for any standard-offer obligations.

Natural Gas

NYSEG, RG&E, CNG, SCG, Berkshire Gas and MNG satisfied their natural gas supply requirements through purchases from BP Energy Company and other natural gas suppliers, natural gas storage capacity contracts and winter peaking supplies and resources. A majority of the natural gas supply purchased was acquired under long- and short-term supply contracts and the remainder was acquired on the spot market. Firm underground natural gas storage capacity is contracted for using long-term contracts. Firm transportation capacity was acquired under long-term contracts and was utilized to transport both natural gas supply purchased and natural gas withdrawn from storage to local distribution systems. Winter peaking supplies and resources are either owned by Energy East, NYSEG and RG&E and are attached to the distribution system, or are contracted for under long-term arrangements.

See Item 7 - MD&A - Natural Gas Delivery Rate Overview, Natural Gas Delivery Business Developments and Commodity Price Risk and Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.

Franchises

Our operating utilities have valid franchises, with minor exceptions, from the municipalities in which they render service to the public.

Seasonal business

Winter peak electricity loads are primarily due to space heating usage and fewer daylight hours. Summer peak electricity loads are due to the use of air-conditioning and other cooling equipment. Our sales of natural gas are highest during the winter months primarily due to space heating usage.

Working capital

Our operating utilities have been granted, through the ratemaking process, an allowance for working capital to operate their ongoing electric and/or natural gas utility systems. Their major working capital requirements include natural gas inventories, which increase during the summer and fall for winter sales; accounts receivable, which are highest during periods of peak sales; and cash requirements to pay for utility construction and operating expenses.

Competitive conditions

In New York, the NYPSC has experimented with programs that require utilities to actively encourage their customers to migrate to ESCO suppliers. NYSEG and RG&E have filed proposed parameters for ESCO referral programs. To date the NYPSC has not acted on these filings and NYSEG and RG&E have requested postponement of the respective tariffs for six months. NYSEG and RG&E are unable to predict the ultimate effect of these programs on their ability to continue to provide commodity service to their customers.

See Item 1A - Risk Factors and Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas Delivery Rate Overview, Natural Gas Delivery Business Developments and Critical Accounting Policies.

Research and development

Our consolidated expenditures for research and development were $3 million in 2006, $4 million in 2005 and $5 million in 2004. RG&E's expenditures were $2 million in 2006, $1 million in 2005 and $2 million in 2004. Expenditures were for internal research programs and contributions to research administered by the NYSERDA, the Electric Power Research Institute and the Northeast Gas Association. Research and development expenditures are intended to improve existing energy technologies and develop new technologies for the delivery and efficient customer use of energy.

Environmental matters

Energy East and RG&E are subject to regulation by the federal government and by state and local governments with respect to environmental matters, such as the handling and disposal of toxic substances and hazardous and solid wastes and the handling and use of chemical products. Electric utility companies generally use or generate a range of potentially hazardous products and by-products that are subject to such regulation. They are also subject to state laws regarding environmental approval and certification of proposed major transmission facilities.

From time to time, environmental laws, regulations and compliance programs may require changes in Energy East's and RG&E's operations and facilities and may increase the cost of energy delivery service. Historically, rate recovery has been authorized for environmental compliance costs.

We made capital expenditures totaling approximately $10 million, including $2.5 million by RG&E, to meet environmental requirements during the three years ended December 31, 2006. Future capital additions for current facilities to meet environmental requirements are not expected to be material. However, we have plans to voluntarily adopt a number of environmentally friendly initiatives, including an advanced metering infrastructure. We may also have significant expenditures for repowering Russell Station using new technology which minimizes emissions.

Water and air quality

: Energy East and RG&E are required to comply with federal and state water quality statutes and regulations including the Clean Water Act. The Clean Water Act requires that generating stations be in compliance with federally issued National Pollutant Discharge Elimination System permits or state issued SPDES permits, which reflect water quality considerations for the protection of the environment. RG&E has SPDES permits for two of its generating stations. The Energy Network owns interests in two natural gas-fired peaking generating stations and TEN Cos. owns and operates two steam plants, all of which have the required federal or state operating permits.

Energy East and RG&E are required to comply with federal and state oil spill statutes and regulations including the Spill Prevention Control and Countermeasures (SPCC) regulations. Revisions to such regulations were recently finalized and require that the company and RG&E update current oil SPCC plans by the proposed date of July 1, 2009, and prepare new SPCC plans for locations that are covered under the regulations. These SPCC locations include electric operations service centers and substations, gas operation centers and liquefied natural gas facilities.

RG&E is required to comply with federal and state air quality statutes and regulations for operation of its coal-fired and combustion turbine generating stations. All of RG&E's generating stations have the required federal or state operating permits. Stack tests and continuous emissions monitoring indicate that the generating stations are generally in compliance with permit emission limitations, although occasional opacity exceedances occur. Efforts continue in the identification and elimination of the causes of opacity exceedances. Russell Station, RG&E's sole coal-fired station, is scheduled to close at the end of 2007 upon the completion of RG&E's transmission project which will substantially reduce the company's and RG&E's emissions. RG&E may also seek the necessary approvals to repower Russell Station using clean coal technologies.

The 1990 Clean Air Act Amendments limit emissions of sulfur dioxide and nitrogen oxides and require emissions monitoring. The EPA allocates annual emissions allowances to RG&E's coal-fired generating station based on statutory emissions limits under Phase II (which began January 1, 2000) of the 1990 Amendments. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. A similar allowance program under Title I of the 1990 Amendments controls nitrogen oxides emissions from RG&E's coal-fired station and a combustion turbine generating station. Another requirement of the 1990 Amendments is for the coal-fired station and a combustion turbine generating station to have a facility operating permit (Title V permit). The Title V permits required for each station have been granted. In 2005 the EPA finalized rules requiring further reductions in sulfur dioxide and nitrogen oxides emissions, as well as mercury emissions from coal-fired generating stations. The reductions will begin in 2009 for nitrogen oxides and 2010 for sulfur dioxide and mercury. However, the methods to achieve the reductions will be proposed by the individually affected states. Except for mercury emissions in New York, these methods have not been proposed by the states in which the company operates at this time. New York has submitted its mercury emissions control implementation plan to the EPA for approval. The first phase takes effect in 2010 and requires each existing coal-fired power plant to meet a facility-wide cap equivalent to a 50% reduction from baseline. New coal-fired units and existing facilities in phase 2 (starting in 2015) will need to meet an emission limit that is approximately equivalent to a 90% reduction. New York will not allow allowance trading to meet compliance as is allowed under the Clean Air Mercury Rule.

Regulations adopted by the state of New York that further limit acid rain precursor emissions from electric generating units, possibly at an additional cost to RG&E, became effective on October 1, 2004, for nitrogen oxides and January 1, 2005, for sulfur dioxide. The current federal summertime limits for nitrogen oxides are now applied year round. Emissions reduction targets are set at 50% below the current federal limits for sulfur dioxide and are being phased in between 2005 and 2008. Emissions reductions will be achieved through a New York State only market-based allowance trading system similar to those under the 1990 Amendments. Beyond the allowances allocated to RG&E, there is limited availability of economically-viable allowances.

RG&E purchases emissions allowances as necessary in order to comply with the Clean Air Act and New York State acid rain regulations and estimates its cost for allowances will be approximately $13 million for 2007. In addition, RG&E has installed control equipment at its facilities at a cost of over $16 million as part of its compliance with the Clean Air Act. If RG&E were unable to satisfy some of its environmental commitments with emissions allowances, either because of regulatory changes or an inability to obtain emissions allowances, RG&E would be required to take alternative actions, which may include reduced plant operation or shutdown, or repowering with clean coal technologies to comply with the Clean Air Act and New York State acid rain regulations.

The federal Regional Greenhouse Gas Initiative (RGGI) will set a cap on carbon dioxide emissions from electric generators at current emission levels starting in 2009, reducing to 10% below the 2009 cap levels incrementally from 2015 to 2018. Seven northeastern states signed a memorandum of understanding in December 2005. A model rule for states to implement the RGGI was finalized in August 2006. Though the model rule specifies that at least 25% of levels are to be auctioned for consumer benefit or strategic energy program, distribution of the remaining 75% is left up to individual states.

New York has issued a "pre-proposal" draft of its RGGI rule which generally follows the model rule. One aspect of the rule is that New York proposed to auction 100% of allowances, with proceeds to be used for "energy efficiency and clean energy technology purposes." Electricity supply generators will be required to purchase necessary allowances to continue operations and there would be a corresponding impact on the cost of the electric supply produced by these generators. The actual draft rule for public comment is expected by mid-2007 with a final rule by late 2007 or early 2008.

Maine, through the Maine Department of Environmental Protection, is in the process of drafting its implementation rules based on the model rule. The draft rule would require specific reductions or allowance purchases by the affected emission sources in Maine and establishes a framework for allowance trading and purchasing carbon dioxide offsets from eligible sources. At this time Maine has not determined if, or how much of, the initial allowances would be auctioned or granted and how any auction proceeds would be applied or distributed. If the allowances are auctioned, electric supply generators would be required to purchase necessary allowances to continue operations and there would be a corresponding increase in the cost of electric supply produced by these generators. The company cannot predict the outcome of this rulemaking or its ultimate impact on the price of electric supply in Maine.

See Item 3 - Legal Proceedings, Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas Delivery Rate Overview, Natural Gas Delivery Business Developments and Item 8 - Note 10 to our Consolidated Financial Statements and Note 9 to RG&E's Financial Statements.

Number of employees

As of January 31, 2007, Energy East had 5,884 employees, including 1,016 RG&E employees.

Financial information about geographic areas

Neither Energy East nor RG&E have foreign operations.

Available information

We make available free of charge through our Internet Web site, http://www.energyeast.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after those reports are electronically filed with the SEC. Access to the reports is available from the main page of our Internet Web site through "Financial Information" and then "SEC filings." Our Code of Conduct and Corporate Governance Guidelines and the charters of the Audit, Compensation and Management Succession, and Nominating and Corporate Governance committees are also available on our Internet Web site. Waivers of the Code of Conduct are not contemplated. However, in the unlikely event of an amendment to, or waiver from, the Code of Conduct applicable to our principal executive, financial and accounting officers, we will post such information through our Web site. Access to these documents is available from the main page of our Internet Web site through "Financial Information" and then "Corporate Governance." Printed copies of these documents are also available upon request by contacting Investor Relations at (207) 688-4336.

Item 1A. Risk Factors

We regularly identify, monitor and assess our exposure to risk and seek to mitigate the risks inherent in our energy services and delivery businesses. However, there are risks that are beyond our control or that cannot be limited cost-effectively or that may occur despite our risk mitigation efforts. The risk factors discussed below could have a material effect on our financial position, results of operation or cash flows.

NYSEG's Electric Rate Order issued by the NYPSC that went into effect on January 1, 2007, will significantly impact NYSEG's earnings potential.

The reduction in rates and changes in NYSEG's commodity supply program reduces NYSEG's earnings potential by $35 million to $45 million, which will have an adverse effect on NYSEG's financial condition and results of operations. In addition, we cannot predict the effect of the Electric Rate Order on our credit ratings.

The NYPSC has experimented with programs that require utilities to actively encourage their customers to migrate to ESCO suppliers.

The NYPSC has experimented with programs to require utilities to actively encourage customers to switch to ESCOs for the purchase of electricity or natural gas. NYSEG and RG&E have developed such "ESCO Referral" programs, and they have been submitted to the NYPSC for review and approval. However, to date, the NYPSC has not acted to implement these programs at RG&E or NYSEG. The NYPSC has also dismantled the Office of Retail Market Development, upon the resignation of its director, and has re-assigned staff to other offices of the NYPSC. We cannot predict the outcome of these proceedings.

Our regulated utilities are subject to substantial governmental regulation on the federal, state and local levels.

On the federal level, the FERC regulates our utilities' transmission rates, affiliate transactions, the issuance of certain short-term debt securities by our electric utilities and certain other aspects of our utilities' businesses. State commissions regulate the rates, terms and conditions of service, various business practices and transactions, financings, and transactions between the utilities and affiliates. Local regulation affects the siting of our transmission and distribution facilities and our ability to make repairs to such facilities. Our allowed rates of return, rate structures, operation and construction of facilities, rates of depreciation and amortization, recovery of costs (including exogenous costs such as storm-related expenses), are all determined by the regulatory process. The timing and adequacy of regulatory relief directly affect our results of operations and cash flows. Furthermore, compliance with regulatory requirements may result in substantial costs in our operations that may not be recovered. We cannot predict the effect that any future changes or revisions to laws and regulations affecting the utility industry may have on our financial position, results of operations or cash flows.

We are a holding company whose material assets are the stock of our subsidiaries.

Accordingly, we conduct all of our operations through those subsidiaries. Our ability to pay dividends on our common stock and to pay principal and accrued interest on our debt depends upon our receipt of dividends from our principal subsidiaries. Payments to us by those subsidiaries depend, in turn, upon their results of operations and cash flows, which are subject to the risk factors discussed in this section. The ability of our subsidiaries to make payments to us is also affected by the level of their indebtedness, and the restrictions on payments to us imposed under the terms of such indebtedness and restrictions imposed by the Federal Power Act.

Our natural gas companies may be affected by various factors that could limit their ability to obtain natural gas supplies.

Supply and demand factors including hurricanes or other natural disasters could affect our future ability to obtain natural gas supplies. Increases in demand and lower supplies can result in higher natural gas prices. While higher costs are generally passed on to customers pursuant to natural gas adjustment clauses, and therefore do not pose a direct risk to our earnings, we are unable to predict what effect increases in natural gas prices may have on our customers' energy consumption or ability to pay.

Transmission projects are subject to regulations and other factors beyond our control.

Our electric utility companies have substantial transmission capital investment programs including an RG&E transmission project of approximately $119 million that has received the required regulatory approvals and proposed transmission projects in Maine that could require significant investment. These transmission projects are expected to increase reliability, meet new load growth requirements and interconnect with new generation, including renewable generation. The regulatory approval process for transmission projects is extensive and we may not be able to obtain the approvals required for our proposed transmission projects. Various factors beyond our control, including an increase in the cost of materials or labor, may increase the cost of completing construction projects and may delay construction.

Our new transmission projects are subject to the effects of new legislation, regulation and regional interpretations of applicable laws and regulations. Any changes to these laws and regulations may increase the costs or timing of our transmission projects.

The FERC has jurisdiction over transmission expansion and generation interconnection. The FERC has issued several orders regarding transmission expansion and generation interconnection cost allocation. Changes to the rules and regulations concerning transmission expansion and generation cost allocations may affect future transmission rates.

RTOs and independent system operators now oversee wholesale transmission services in NYSEG's, RG&E's, and CMP's service territories and between regions. Our transmission facilities are operated by and subject to the rules and regulations of the NYISO and ISO-NE. Changes to those rules and regulations could cause us to incur additional expenses to maintain our facilities.

Our ability to provide energy delivery and commodity services depends on the operations and facilities of third parties.

These third party facilities include independent system operators, electric generators from whom we purchase electricity and natural gas pipeline operators from whom we receive shipments of natural gas. The loss of use or destruction of our facilities or the facilities of third parties that are used in providing our services, or with which our electric or natural gas facilities are interconnected, due to extreme weather conditions, breakdowns, war, acts of terrorism or other occurrences could greatly reduce potential earnings and cash flows and increase our costs of repairs and/or replacement of assets. While we carry property insurance to protect certain assets and have regulatory agreements that provide for the recovery of losses for such incidents, our losses may not be fully recoverable through insurance or customer rates.

The demand for our services is directly affected by weather conditions.

The demand for our services, especially our natural gas delivery service, is directly affected by weather conditions. Milder winter months or cooler summer months could greatly reduce our earnings and cash flows. Loss of revenue due to power outages in severe weather could also reduce our earnings or require us to defer some costs for future recovery, thus reducing our cash flow. While our natural gas distribution companies mitigate the risk of warmer winter weather through weather normalization clauses or weather insurance, and we have historically been able to defer major storm costs for future recovery, we may not always be able to fully recover all lost revenues or increased expenses.

We

use derivative instruments, such as swaps, options, futures and forwards to manage our commodity and financial market risks.

We could recognize financial losses as a result of volatility in the market values of these contracts. We also bear the risk of a counterparty failing to perform. While we employ prudent credit policies and obtain collateral where appropriate, counterparty credit exposure cannot be eliminated, particularly in volatile energy markets.

Our ability to hedge our commodity market risk depends on our ability to accurately forecast demand in future periods. Because of changes in weather and customer demand from period to period, we may hedge amounts that are greater or less than our actual commodity deliveries. Such differences may lead to financial losses and, if the differences exceed certain levels, could result in our hedges becoming ineffective under accounting guidance. Gains or losses on ineffective hedges are marked-to-market on our income statement without reference to our underlying sale of the commodity.

Prices for electricity and natural gas are subject to volatility in response to changes in supply and other market conditions.

We pass commodity price increases on to electric customers who choose a variable price option and to all natural gas customers. We have a comprehensive hedging program in place to mitigate the price risk for the load required for electric customers who choose a fixed price option under NYSEG's and RG&E's current commodity option programs. Higher prices passed on to customers can lead to higher bad debt expense and customer conservation resulting in reduced demand for our energy services.

Our pension plan assets are primarily made up of equity and fixed income investments.

Any fluctuations in the performance of those markets, as well as changes in interest rates, could increase our funding requirements for pension and postretirement benefit obligations and cause us to recognize increased expense. In addition, the cost to implement regulatory requirements and potential revisions to accounting standards could affect our financial position, results of operations or cash flow.

Our business follows the economic cycle of the customers in the regions that we serve.

A falling, slow or sluggish economy as found in our upstate New York service territories and reduced demand for electricity and/or natural gas in the areas in which we do business - through forced temporary plant shutdowns, closing operations or slow economic growth - would reduce our earnings potential in the affected region.

We are subject to extensive federal and state environmental regulation.

Our subsidiaries' operations are subject to extensive federal, state and local environmental laws, rules and regulations that monitor, among other things, emission allowances, pollution controls, maintenance, site remediation, upgrading equipment and management of hazardous waste. Various governmental agencies require us to obtain environmental licenses, permits, inspections and approvals. Compliance with environmental laws and requirements can impose significant costs, reduce cash flows and result in plant shutdowns.

Our ability and/or cost to access capital could be negatively affected by changes in our financial position, results of operations or cash flows.

If any of our utility subsidiaries' credit ratings were to be downgraded, our ability to access the capital markets, including the commercial paper markets, could be adversely affected and our borrowing costs would increase. Some of the factors that affect credit ratings are cash flows, liquidity and the amount of debt as a component of total capitalization. An example of a factor that could cause our subsidiaries' debt as a component of total capitalization to increase is the need to borrow money to pay for unexpected repairs to their transmission and distribution systems caused by a catastrophic event.

The application of our critical accounting policies reflects complex judgments and estimates.

Those policies include industry-specific accounting standards applicable to our rate-regulated utilities, accounting for goodwill and other intangible assets, pension and other postretirement benefit plans, unbilled revenue and allowance for doubtful accounts. The adoption of new accounting standards, changes to current accounting standards or interpretations of such standards may materially affect our financial position, results of operations or cash flows.

The NYPSC proceeding regarding NYSEG's OPEB reserve could have a significant one-time impact on earnings.

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 we are vigorously opposing staff on these issues, contending that the NYPSC staff is engaged in retroactive ratemaking, we cannot predict how this matter will be resolved.

Item 1B. Unresolved Staff Comments

None for Energy East or RG&E.

Item 2. Properties

See Item 7 - MD&A - Electric Delivery Business Developments.

NYSEG's electric system includes hydroelectric and gas turbine generating stations, substations and transmission and distribution lines, substantially all of which are located in the state of New York.

RG&E's electric system includes coal-fired, combustion turbine and hydroelectric generating stations, substations and transmission and distribution lines, all of which are located in the state of New York.

CMP's electric system includes substations and transmission and distribution lines, all of which are located in the state of Maine.

The Energy Network owns interests in two natural gas-fired peaking generating stations: one located in the state of New York and operated by Cayuga Energy, a wholly-owned subsidiary; and one located in the state of Pennsylvania for which Cayuga Energy manages fuel procurement and electricity sales.

The operating companies' generating facilities consist of:

Operating Company	Type and location of station		Generating capability (MWs)
NYSEG	Gas turbine	(Newcomb, NY)	2
NYSEG	Gas turbine Hydroelectric	(Auburn, NY)	7
NYSEG	Hydroelectric	(Various - 7 locations)	60
RG&E		(Rochester, NY - 3 locations)	47
RG&E	Coal-fired	(Greece, NY)	257
RG&E	Gas turbine	(Hume, NY)	63
RG&E	Gas turbine	(Rochester, NY - 2	28
The Energy Network	Gas turbine	locations)	67
The Energy Network	Gas turbine	(Carthage, NY)	24[1]
		(Archbald, PA)	
Total			555

[1] Cayuga Energy's 50.1% share of the generating capability.

CMP owns the following percentages of stock in three companies with nuclear generating facilities: Maine Yankee in Wiscasset, Maine, 38%; Yankee Atomic in Rowe, Massachusetts, 9.5%; and Connecticut Yankee in Haddam, Connecticut, 6%. The three facilities have been permanently shut down. Maine Yankee completed its decommissioning in 2005 and Yankee Atomic completed its decommissioning in 2006. Connecticut Yankee expects to complete its decommissioning in 2007. Each of the three facilities 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.

(See Item 7 - MD&A - CMP Nuclear Costs.)

CMP owns 311 substations in the state of Maine having an aggregate transformer capacity of 6,772,787 kilovolt-amperes. The transmission system consists of 2,564 circuit miles of line. The distribution system consists of 21,984 pole miles of overhead lines and 1,255 miles of direct bury and network underground lines.

NYSEG owns 439 substations in the state of New York having an aggregate transformer capacity of 15,221,800 kilovolt-amperes. The transmission system consists of 4,400 circuit miles of line. The distribution system consists of 30,521 pole miles of overhead lines and 2,063 miles of direct bury and network underground lines.

RG&E owns 164 substations in the state of New York having an aggregate transformer capacity of 6,480,400 kilovolt-amperes. The transmission system consists of 763 circuit miles of overhead lines and 502 circuit miles of underground lines. The distribution system consists of 17,258 circuit miles of overhead lines and 5,274 circuit miles of underground lines.

The operating utilities' natural gas systems consist of:

Operating Company	Location	Miles of Transmission Pipeline	Miles of Distribution Pipeline
NYSEG	New York State	72	7,878
RG&E	New York State	109	8,471
SCG	Connecticut	-	3,722
CNG	Connecticut	-	3,657
Berkshire Gas	Massachusetts	-	733
MNG	Maine	2	80
New Hampshire Gas (Propane air)	New Hampshire	-	28

NYSEG owns the Seneca Lake Natural Gas Storage Facility, which is able to store approximately 1.4 billion cubic feet of natural gas. As of December 31, 2006, the facility was at approximately 95% of capacity.

A portion of our utility plant is subject to liens or mortgages securing certain of our subsidiaries' first mortgage bonds. None of CMP's, NYSEG's or CNG's utility plant is subject to liens or mortgages securing first mortgage bonds. RG&E, Berkshire Gas and SCG have first mortgage bond indentures that constitute a direct first mortgage lien on substantially all of their respective properties. (See Item 8 - Note 6 to our Consolidated Financial Statements and Note 5 to RG&E's Financial Statements.)

Item 3. Legal Proceedings

See Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas

Delivery Rate Overview and Natural Gas Delivery Business Developments and Item 8 - Note 10 to our Consolidated Financial Statements and Note 9 to RG&E's Financial Statements.

Since the NYPSC, DPUC, MPUC and DTE have allowed our operating utilities to recover in rates remediation costs for certain of the sites referred to in the second and fourth paragraphs of Note 10 to our Consolidated Financial Statements and Note 9 to RG&E's Financial Statements, there is a reasonable basis to conclude that such operating utilities will be permitted to recover in rates any remediation costs that they may incur for all of the sites referred to in those paragraphs. Therefore, Energy East and RG&E believe that the ultimate disposition of the matters referred to in the paragraphs of the Notes referred to above will not have a material adverse effect on their results of operations, financial position or cash flows.

(a) In October 1999 RG&E received a letter from the New York State Attorney General's office alleging that RG&E may have constructed and operated major modifications to the Beebee and Russell generating stations without obtaining the required prevention of significant deterioration or new source review permits. The letter requested that RG&E provide the Attorney General's office with a large number of documents relating to this allegation. In January 2000 RG&E received a subpoena from the NYSDEC ordering production of similar documents. RG&E supplied documents and complied with the subpoena.

The NYSDEC served RG&E with a notice of violation in May 2000 alleging that between 1983 and 1987 RG&E completed five projects at Russell Station and two projects at Beebee Station, which is currently shut down, without obtaining the appropriate permits. RG&E believes it has complied with the applicable rules and there is no basis for the Attorney General's and the NYSDEC's allegations. Beginning in July 2000 the NYSDEC, the Attorney General and RG&E had a number of discussions with respect to resolution of the notice of violation. In October 2006 the Attorney General's office and the NYSDEC notified RG&E of their intention to file a complaint in federal court for violations at Russell Station unless a settlement can be reached. Were the Attorney General and the NYSDEC to commence a Clean Air Act lawsuit against RG&E, they would need to demonstrate, among other things, that the challenged modifications to the Russell generating station cause an "increase" in emissions from the station. The issue of what constitutes the appropriate test for an emissions increase currently is before the United States Supreme Court in Environmental Defense v. Duke Energy Corporation, Docket No. 05-848. Oral argument was held on November 2006, and a decision is expected in the first half of 2007. RG&E, the NYSDEC and the Attorney General continue to discuss this matter and no suit has been filed to date. RG&E is not able to predict the outcome of this matter.

(b) The State of Connecticut filed suit in February 2007 against Energy East and its affiliates TEN Companies, CNG and CTG Resources, Inc. for an alleged $14 million overcharge for heating and cooling services supplied to state buildings since 1992. While the company believes that there is no merit to this action, it cannot predict the outcome of this matter.

Item 4. Submission of Matters to a Vote of Security Holders

None for Energy East or RG&E.

* * * * * * * * * * *

Executive Officers of the Registrants

(Identification of executive officers is inserted in Part

I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2006.

Energy East Corporation

Name and Position	Age	Period served	Business experience - January 2002 to date
Wesley W. von Schack Chairman, President and Chief Executive Officer	62	to date	Chairman, President and Chief Executive Officer
Robert E. Rude Senior Vice President and Chief Regulatory Officer	53	2005 to date to 2005	Senior Vice President and Chief Regulatory Officer Vice President and Controller
Richard R. Benson Senior Vice President and Chief Administrative Officer	49	2007 2005 to 2007 2004 to 2005 to 2004	Senior Vice President and Chief Administrative Officer Vice President and Chief Administrative Officer Vice President, Administrative Services of Energy East Management Corporation Vice President, Human Resources of Energy East Management Corporation
Robert D. Kump Senior Vice President and Chief Financial Officer	45	2007 2005 to 2007 2002 to 2005 to 2002	Senior Vice President and Chief Financial Officer Vice President, Controller and Chief Accounting Officer Vice President, Treasurer and Secretary Vice President and Treasurer
F. Michael McClain Senior Vice President and Chief Development and Integration Officer	57	2007 2005 to 2007 2003 to 2005 to 2003	Senior Vice President and Chief Development and Integration Officer Vice President - Finance, Treasurer and Chief Integration Officer Vice President, Finance and Chief Integration Officer of Energy East Management Corporation Vice President, Finance of Energy East Management Corporation
Paul K. Connolly, Jr. Vice President - General Counsel	62	2006 to date to 2005	Vice President - General Counsel Partner - LeBoeuf, Lamb, Greene and MacRae LLP

Angela M. Sparks-Beddoe Vice President, Public Affairs of Energy East Management Corporation	42	to date	Vice President, Public Affairs of Energy East Management Corporation

New York State Electric & Gas Corporation
Rochester Gas and Electric Corporation

Name and Position	Age	Period served	Business experience - January 2002 to date
James P. Laurito President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation	50	2005 to date	President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation
		2004 to 2005	President of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation
		2003 to 2004	President and Treasurer of New York State Electric & Gas Corporation
		to 2003	President and Chief Operating Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company

Central Maine Power Company

Name and Position	Age	Period served	Business experience - January 2002 to date
Sara J. Burns President and Chief Executive Officer of Central Maine Power Company	51	2005 to date	President and Chief Executive Officer of Central Maine Power Company
		to 2005	President of Central Maine Power Company

The Berkshire Gas Company
Connecticut Natural Gas Corporation
The Southern Connecticut Gas Company

Name and Position	Age	Period served	Business experience - January 2002 to date
Robert M. Allessio	56	2005 to date	President and Chief Executive Officer of Connecticut Natural Gas Corporation and The Southern

President and Chief Executive Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company Chairman and Chief Executive Officer of The Berkshire Gas Company		 2004 to date 2004 to 2005 2003 to 2004 to 2004 to 2003	Connecticut Gas Company Chairman and Chief Executive Officer of The Berkshire Gas Company Executive Vice President and Chief Operating Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company Senior Vice President, Operating Services of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company President, Chief Executive Officer and Treasurer of The Berkshire Gas Company Vice President, Operating Services of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company
Karen L. Zink President, Treasurer and Chief Operating Officer of The Berkshire Gas Company	49	2004 to date 2003 to 2004 to 2003	President, Treasurer and Chief Operating Officer of The Berkshire Gas Company Vice President and General Manager of The Berkshire Gas Company Vice President of The Berkshire Gas Company

Wesley W. von Schack has an employment agreement for a term ending June 30, 2007. Mr. von Schack's agreement provides for his employment as Chairman, President & Chief Executive Officer of the company. The agreement provides for automatic one-year extensions unless either party gives notice that such agreement is not to be extended.

Robert M. Allessio, Sara J. Burns and F. Michael McClain each have an employment agreement, which is automatically extended each month unless either party to an agreement gives written notice that it is not to be extended. Ms. Burns' agreement provides for her employment as President of CMP and Mr. Allessio's agreement provides for his employment as Chief Executive Officer of Berkshire Gas.

Each officer holds office for the term for which he or she is elected or appointed, and until his or her successor is elected and qualifies. The term of office for each officer extends to and expires at the meeting of the Board of Directors following the next annual meeting of shareholders.

PART II

Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange. The number of shareholders of record was 29,896 at January 31, 2007.

Quarter Ended	March 31	June 30	September 30	December 31
2006				
Dividends Declared per Share	$.29	$.29	$.29	$.30
Common Stock Price				
High	$25.57	$25.39	$25.20	$25.66
Low	$22.98	$22.18	$23.36	$23.62
2005				
Dividends Declared per Share	$.275	$.275	$.275	$.29
Common Stock Price				
High	$26.95	$30.07	$29.35	$25.95
Low	$24.98	$25.09	$24.82	$22.50

RGS Energy, a wholly-owned subsidiary of Energy East, owns all of RG&E's common stock. See Item 8 - RG&E's Statements of Changes in Common Stock Equity for information regarding dividends declared.

Equity Compensation Plan Information

The following table provides information as of December 31, 2006, with respect to shares of common stock that may be issued under Energy East's 2000 Stock Option Plan and its Restricted Stock Plan.

Plan category	(a) Number of securities to be issued upon exercise of outstanding options and SARs	(b) Weighted-average exercise price of outstanding options and SARs	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity Compensation Plan Approved by Stockholders (2000 Stock Option Plan)	3,658,555	$24.03	6,731,246
Equity Compensation Plan Not Approved by Stockholders (Restricted Stock Plan) (1)	N/A	N/A	995,624
Total	3,658,555		7,726,870

(1) See Item 8 - Note 12 to our Consolidated Financial Statements for information regarding the Restricted Stock Plan.

Issuer Purchases of Equity Securities

Energy East Corporation

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number of shares that may yet be purchased under the plans or programs
Month #1 (October 1, 2006 to October 31, 2006)	4,941(1)	$24.03	-	-
Month #2 (November 1, 2006 to November 30, 2006)	4,919(1)	$23.94	-	-
Month #3 (December 1, 2006 to December 31, 2006)	6,189(1)	$25.32	-	-
Total	16,049	$24.50	-	-

(1)

Represents shares of our common stock (Par Value $.01) purchased in open-market transactions on behalf of our Employees' Stock Purchase Plan.

RG&E had no issuer purchases of equity securities during the quarter ended December 31, 2006.

Item 6. Selected Financial Data

See the information under the heading Selected Financial Data for Energy East, which is included on page

II-23.

RG&E meets the conditions set forth in General Instruction I (1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, the Item 6 information related to RG&E is not presented.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

See the information under the heading Management's Discussion and Analysis of Financial Condition and Results of Operations for Energy East, which is included in this report on pages

II-24 to II-55.

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 including a management's narrative analysis of the results of operations as specified in General Instruction I(2)(a) of Form 10-K. See information under the heading Management's Narrative Analysis of Results of Operations for RG&E, which is included in this report on pages II-97 to II-98.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Item 7 - MD&A - Market Risk for Energy East and see the Notes to Financial Statements in Item 8 that are referred to in Energy East's Market Risk disclosure.

See Item 7A - Quantitative and Qualitative Disclosures about Market Risk for RG&E on page

II-99 and see the Notes to Financial Statements in Item 8 that are referred to in RG&E's Item 7A disclosures.

Item 8. Financial Statements and Supplementary Data

Index to 2006 Financial Statements

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None for Energy East or RG&E.

Item 9A. Controls and Procedures

Management's Annual Report on Disclosure Controls and Procedures

The principal executive officers and principal financial officers of Energy East and RG&E evaluated the effectiveness of their respective company's disclosure controls and procedures as of the end of the period covered by this report. "Disclosure controls and procedures" are controls and other procedures of a company that are designed to ensure that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, within the time periods specified in the SEC rules and forms, is recorded, processed, summarized and reported, and is accumulated and communicated to the company's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Based on their evaluation, the principal executive officers and principal financial officers of Energy East and RG&E concluded that their respective company's disclosure controls and procedures are effective.

Energy East Management's Annual Report on Internal Control Over Financial Reporting

Energy East's management is responsible for establishing and maintaining adequate internal control over financial reporting. 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 accounting principles generally accepted in the United States of America. Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, an evaluation was conducted of the effectiveness of the internal control over financial reporting based on the framework in *Internal*

Control - Integrated Framework issued by The Committee of Sponsoring Organizations of the Treadway Commission. Based on Energy East's evaluation under the framework in *Internal Control - Integrated Framework*, management concluded that Energy East's internal control over financial reporting was effective as of December 31, 2006.

Energy East management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page II-94.

Changes in Internal Control over Financial Reporting

On October 1, 2006, RG&E modified certain internal controls over financial reporting to accommodate the implementation of a new customer care system. The customer care system is used for customer bill production and integrates RG&E's revenue, accounts receivable and cash management transactions with Energy East's centralized accounting system.

There were no other changes in Energy East's or RG&E's internal control over financial reporting that occurred during each company's most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the respective company's internal control over financial reporting.

Item 9B. Other Information

None for Energy East or RG&E.

Selected Financial Data

Energy East Corporation

	2006	2005	2004	2003	2002 (1)
(Thousands, except per share amounts)					
Operating Revenues	$5,230,665	$5,298,543	$4,756,692	$4,514,490	$3,778,026
Depreciation and amortization	$282,568	$277,217	$292,457	$299,430	$240,306
Other taxes	$249,834	$246,271	$252,860	$269,238	$229,158
Interest Charges, Net	$308,824	$288,897	$276,890	$284,482	$256,161
Income from Continuing Operations	$259,832	$256,833	$237,621	$208,490	$189,929
Net Income	$259,832	$256,833	$229,337	$210,446	$188,603 (2)
Earnings per Share from Continuing Operations, basic	$1.77	$1.75	$1.63	$1.43	$1.45 (2)
Earnings per Share from Continuing Operations, diluted	$1.76	$1.74	$1.62	$1.43	$1.45 (2)
Earnings per Share, basic	$1.77	$1.75	$1.57	$1.45	$1.44 (2)
Earnings per Share, diluted	$1.76	$1.74	$1.56	$1.44	$1.44 (2)

Dividends Declared per Share	$1.17	$1.115	$1.055	$1.00	$.96
Average Common Shares Outstanding, basic	146,962	146,964	146,305	145,535	131,117
Average Common Shares Outstanding, diluted	147,717	147,474	146,713	145,730	131,117
Utility Capital Spending	$408,231	$331,294	$299,263	$289,320	$229,387
Total Assets	$11,562,401	$11,487,708	$10,796,622	$11,330,441	$10,944,347
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	$3,726,709	$3,667,065	$3,797,685	$4,017,846	$3,721,959

(1) Due to the completion of our merger transaction during 2002 the consolidated financial statements include RGS Energy's results beginning with July 2002.
(2) Includes the writedown of our investment in NEON Communications, Inc. that decreased net income $7 million and EPS 6 cents and the effect of restructuring expenses that decreased net income $24 million and EPS 19 cents.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Overview

Energy East's primary operations, our electric and natural gas utility operations, are subject to rate regulation established predominately by state utility commissions. The approved regulatory treatment on various matters significantly affects our financial position, results of operations and cash flows. We have long-term rate plans for NYSEG's natural gas segment, RG&E, CMP and Berkshire Gas that currently allow for recovery of certain costs, including stranded costs; and provide stable rates for customers and revenue predictability. Where long-term rate plans are not in effect, we monitor the adequacy of rate levels and file for new rates when necessary. NYSEG's five-year electric rate plan expired December 31, 2006, and new rates went into effect on January 1, 2007. SCG received approval for new rates that became effective January 1, 2006, and CNG recently entered into a settlement agreement that, if approved, will result in new rates effective April 1, 2007. As of January 31, 2007, Energy East had 5,884 employees.

We continue to focus our strategic efforts on the areas that have the greatest effect on customer satisfaction and shareholder value. NYSEG implemented a new customer care system in the first quarter of 2006 and RG&E implemented a similar system in October 2006.

The continuing uncertainty in the evolution of the utility industry, particularly the electric utility industry, has resulted in several federal and state regulatory proceedings that could significantly affect our operations and the rates that our customers pay for energy. Those proceedings, which are discussed below, could affect the nature of the electric and natural gas utility industries in New York and New England.

We expect to make significant capital investments to enhance the safety and reliability of our distribution systems and to meet the growing energy needs of our customers in an environmentally responsible manner. Capital spending is expected to exceed $3 billion through 2011, including $496 million in 2007. Major spending programs include the installation of advanced metering infrastructure in New York and Maine requiring a $500 million investment; $500 million of transmission investments, predominantly in Maine; a high efficiency transformer replacement program; and a "green" fleet initiative. The majority of these planned transmission investments will be pursuant to a regional reliability planning process and will qualify for the FERC's transmission investment ROE incentive adders. (See New England RTO.) We will also be investigating the repowering of the Russell Station using clean coal technologies, at a potential estimated cost of approximately $500 million. We estimate that over one-half of our capital spending program will be funded with internally generated funds and the remainder through the issuance of a combination of debt and equity securities.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Strategy

We have maintained a consistent energy delivery and services strategy over the past several years, focusing on the safe, secure and reliable transmission and distribution of electricity and natural gas. Our operating companies have become increasingly efficient through realization of merger-enabled synergies. The company intends to augment this strategic focus by addressing many of the precepts of the Energy Policy Act of 2005 including: a) investing in transmission to increase reliability, meet new load growth and connect new, renewable generation to the grid; b) investing in advanced metering infrastructure to promote customer conservation and peak load management; c) investing in our distribution infrastructure to make it more efficient by reducing losses; and d) investing in new regulated generation that is environmentally friendly and, where possible, sustainable.

Our individual company rate plans are a critical component of our success. While specific provisions may vary among our public utility subsidiaries, our overall strategy includes creating stable rate environments that allow those subsidiaries to earn a fair return while minimizing price increases and sharing achieved savings with customers.

Electric Delivery Rate Overview

Our electric delivery business consists primarily of our regulated electricity transmission, distribution and generation operations in upstate New York and Maine. The electric industry is regulated by various state and federal agencies, including state utility commissions and the FERC. The following is a brief overview of the principal rate agreements in effect for each of our electric utilities.

Electric Rate Plans

: NYSEG had an electric rate plan that took effect as of January 1, 2002, and expired on December 31, 2006. That rate plan provided for equal sharing of the greater of ROEs in excess of 12.5% on electric delivery, or 15.5% on the total electric business (including commodity earnings that over the term of the rate plan were estimated to be $25 million to $40 million on an annual basis based on future energy prices at the time the plan was approved) for each of the years 2003 through 2006. For purposes of earnings sharing, NYSEG was required to use the lower of its actual equity or a 45% equity ratio. At December 31, 2006, the equity NYSEG used for earnings sharing approximated $740 million, which was based on the 45% equity ratio limitation. Earnings levels were sufficient to generate estimated pretax sharing with customers of $5 million in 2006, $28 million in 2005, and $17 million in 2004.

On August 23, 2006, the NYPSC issued an order requiring that NYSEG reduce its electric delivery rates by approximately $36 million, or approximately 6%, effective January 1, 2007. (See NYSEG Electric Rate Order .)

RG&E's current rates were established by the 2004 Electric Rate Agreement, which addresses RG&E's electric rates through at least 2008. Key features of the Electric Rate Agreement include freezing electric delivery rates through December 2008, except for the implementation of a retail access surcharge effective May 1, 2004, to recover $7 million annually. An ASGA was established that was originally estimated to be $145 million at the end of 2008 and will be used at that time for rate moderation or other purposes at the discretion of the NYPSC. The

Electric Rate Agreement also established an earnings-sharing mechanism to allow customers and shareholders to share equally in earnings above a 12.25% ROE target. Earnings levels were sufficient to generate $6 million of pretax sharing in 2006 and $23 million in 2005.

NYSEG and RG&E currently offer their retail customers choice in their electricity supply including a fixed rate option, a variable rate option under which rates vary monthly based on the actual cost of electricity purchases and an option to purchase electricity supply from an ESCO. Both NYSEG's and RG&E's customers make their supply choice annually. Those customers who do not make a choice are served under a variable price option. Customers also pay nonbypassable wires charges, which include recovery of stranded costs. The table below shows the percentages of load that are projected to be served under the various commodity supply options for 2007.

	NYSEG	RG&E
Fixed Price Option	17%	21%
Variable Price Option	45%	29%
Energy Service Company Option	38%	50%

Experience has shown that the majority of our residential and small commercial customers want their utility to remain a supply option and prefer a fixed price option. NYSEG and RG&E believe that their programs are among the most successful of any retail access plans in New York State in terms of active participation and customer migration. In addition, their programs have produced customer benefits in excess of $130 million through 2006. Customer benefits include the customer's portion of earnings sharing and costs that were absorbed by NYSEG and RG&E that would otherwise have been deferred for future recovery had earnings levels been insufficient to generate sharing.

CMP's distribution costs are recovered under the ARP 2000, which became effective January 1, 2001, and continues through December 31, 2007, with price changes, if any, occurring on July 1. CMP's annual delivery rate adjustments are based on inflation with productivity offsets of 2.75% in 2006 and 2.9% in 2007. Price adjustments since 2002 have generally resulted in rate decreases.

CMP uses formula rates for transmission that are FERC regulated. The formula rates provide for the recovery of CMP's cost of owning, operating and maintaining its local and regional transmission facilities and local control center, including a FERC-approved base level ROE of 10.9%, plus a 50 basis point adder for regional facilities and a 100 basis point adder applicable to regional facilities placed in service after December 31, 2003, and approved as part of the ISO-NE regional planning process. The formula rates are updated annually in a filing to the FERC on June 1st. CMP's transmission rates increased approximately $20 million for the rate year effective June 1, 2006. The increase enables CMP to recover its share of ISO-NE regional transmission costs and its local transmission costs.

Pursuant to Maine statutes, CMP recovers the above-market costs of its purchased power agreements, as well as costs incurred to decommission and dismantle the nuclear facilities in which CMP has an ownership share, through its stranded cost rates. In January 2005 the MPUC approved new stranded cost rates for the three-year period ending February 2008. Any difference between actual and projected stranded costs is deferred for future refund or recovery. CMP is prohibited by state law from providing commodity service to its customers.

Electric Delivery Business Developments

NYSEG Electric Rate Order

: In September 2005 NYSEG filed a six-year Electric Rate Plan Extension with the NYPSC, to commence on January 1, 2007. NYSEG's Electric Rate Plan Extension, as subsequently amended, proposed, beginning on January 1, 2007, to reduce the nonbypassable wires charge by $168 million and increase delivery rates by $104 million, thereby resulting in an annualized overall electricity delivery rate decrease of $64 million, or 8.6%. NYSEG proposed to accomplish the reduction in its nonbypassable wires charge by accelerating benefits from certain expiring above-market NUG contracts and capping the amount of above-market NUG costs over the term of the rate plan extension (referred to as NYSEG's NUG levelization proposal). NYSEG also proposed to increase its equity ratio from 45% to 50%. In addition, NYSEG's proposal would have allowed customers to continue to benefit from merger synergies and savings.

In early February 2006 Staff of the NYPSC (Staff) and six other parties submitted their direct cases. Staff presented only a one-year rate case. In its presentation, Staff proposed a delivery rate decrease of approximately $83 million, or about 13.4%. Staff neither rebutted nor addressed NYSEG's revised and updated rate plan extension proposal, including its NUG levelization proposal, and opposed NYSEG's proposal to extend its Voice Your Choice commodity program. Staff also raised several retroactive accounting issues that will be addressed in a future proceeding. The most significant of those issues concerns NYSEG's internal other post employment benefits (OPEB) reserve (explained below), which, if accepted by the NYPSC, would have a material effect on earnings.

On August 23, 2006, the NYPSC issued its order in this proceeding. Major provisions of the Order include:

- A decrease in delivery rates of $36 million. NYSEG's most recent update in the proceeding requested a $58 million increase in delivery rates.
- A 9.55% ROE. NYSEG had requested an 11% ROE.

- An equity ratio of 41.6% (approximately $610 million of equity) based on Energy East's consolidated capital structure. NYSEG had requested a 50% equity ratio based on its actual capital structure.

- A refund of $77 million to be paid from NYSEG's ASGA that had previously been reserved for customers. The ASGA was initially created in 1998 as a result of the sale of NYSEG's generating stations and had been enhanced during NYSEG's prior electric rate plans with the customers' share of earnings from the earnings sharing mechanism. Payment of the refund will be made through a credit to customers' bills by the end of April 2007.

-

- One retroactive accounting issue raised by Staff concerns $57 million of interest associated with NYSEG's internal OPEB reserve, which NYSEG has offset against other OPEB costs in its income statement over the past decade. The NYPSC determined that $3.6 million in annual revenues that NYSEG receives will remain subject to refund pending further examination of NYSEG's accounting for OPEB costs. A proceeding related to this issue began in the fourth quarter of 2006 and could 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. NYSEG is vigorously defending its position and contends that the NYPSC staff is engaged in retroactive ratemaking, but is unable to predict its outcome.

- Significant modifications to NYSEG's previously approved Voice Your Choice commodity program, including:

  - Use of the variable rate supply option as the default for all customers not making a supply election, rather than the previous fixed price default option.

  - A 30% reduction in the cost allowance used to set the supply rate.

  - The use of an earnings collar for supply of plus or minus $5 million pre-tax with sharing outside the collar of 80% to customers and 20% to shareholders. NYSEG previously could earn 300 basis points ROE on supply (approximately $22 million) after which earnings were shared equally.

NYSEG believes that the commodity options program in the Order is unworkable in the long-term and inconsistent with the development of a competitive retail market for supply. In particular, NYSEG believes that the lower cost allowance used to set the supply rate does not cover the cost and risk of providing fixed price electricity at retail, and will stifle participation by retail energy service providers.

NYSEG estimates that the effect of the order will be to reduce its earnings by $35 million to $45 million. This estimate includes the effects of the delivery rate reduction, the lower ROE, the lower equity base that NYSEG is allowed to earn on and the changes in the commodity program, including the revised sharing provisions.

On September 7, 2006, NYSEG filed a petition with the NYPSC for rehearing and request for oral argument responding to certain aspects of the Order including the disallowance of system implementation costs. On December 15, 2006, the NYPSC denied NYSEG's petition.

Niagara Power Project Relicensing

: The NYPA's FERC license with respect to the Niagara Power Project expires on August 31, 2007. In order to continue to operate the Niagara Power Project, the NYPA filed a relicensing application in August 2005. The NYPA's relicensing process is important to NYSEG's and RG&E's customers because an aggregate of over 360 MWs of Niagara Power Project power has been allocated to the companies based on their contracts with the NYPA. (NYSEG and RG&E also receive allocations from the St. Lawrence Project pursuant to those same contracts.) The contracts expire on August 31, 2007, upon termination of the NYPA's FERC license. The annual value of the Niagara allocation to the companies at current electricity market prices is approximately $77 million and the loss of the

allocation would increase NYSEG's and RG&E's residential customer rates. However, the NYPA has stated that the allocation of Niagara Power Project power to NYSEG and RG&E should not be addressed in the relicensing proceeding and that the disposition of the power will be in accordance with state and federal requirements.

Advanced Metering Infrastructure

: In February 2007 in response to an August 2006 NYPSC order, NYSEG and RG&E filed a plan to install advanced metering infrastructure (smart meters) for all of their electric and natural gas customers. Smart meters would enable customers to better control their energy usage by providing time-differentiated rates. Smart meters would also improve the companies' response to service interruptions, enhance safety, and provide internal usage and demand data that will ultimately lead to peak demand reduction and defer the need for generation sources. The plan calls for a total capital investment of approximately $370 million between 2008 and 2010.

Errant Voltage

: In January 2005 the NYPSC issued an Order Instituting Safety Standards in response to a pedestrian being electrocuted from contact with an energized service box cover in New York City. The incident occurred outside of our service territory. All New York utilities were directed to respond to that order by February 19, 2005, with a report that provided a detailed voltage testing program, an inspection program and schedule, safety criteria applied to each program, a quality assurance program, a training program for testing and inspections and a description of current or planned research and development activities related to errant voltage and safety issues. The order also established penalties for failure to achieve annual performance targets for testing and inspections, at 75 basis points each.

In early February 2005 NYSEG and RG&E filed, with two other New York State utilities, a joint petition for rehearing that focused on several areas including the impracticability of the timetable established in the order. In response to the order, in late February 2005 NYSEG and RG&E filed a testing and inspection plan that is consistent with the timetable identified in the joint petition for rehearing. NYSEG and RG&E are implementing their plans, including testing of equipment. On July 21, 2005, in response to the petition for rehearing, the NYPSC issued an order detailing the revised requirements for stray voltage testing and reduced penalties during the first year to 37.5 basis points. NYSEG and RG&E filed the required annual reports with the NYPSC on January 17, 2006. In August 2006

NYSEG and RG&E completed their first complete cycle of testing and at the request of the NYPSC, submitted an interim report on October 23, 2006, detailing their results. Under the provisions of their respective rate plans, they are allowed to defer and recover these costs.

For 2006, costs incurred to comply with the order were approximately $4 million for NYSEG and $2 million for RG&E. For 2007, estimated additional costs to comply with the order are approximately $6 million for NYSEG and $3 million for RG&E.

RG&E Transmission Project

: In December 2004 RG&E received approval from the NYPSC to upgrade its electric transmission system in order to provide sufficient transmission and ensure reliable service to customers in anticipation of the shutdown of the Russell Station. The project includes building or rebuilding 38 miles of transmission lines and upgrading substations in the Rochester, New York area. In August 2005 RG&E selected the team of EPRO Engineering, E.S. Boulos and O'Connell Electric Company for the project. Construction on the project began in the first quarter of 2006 and is expected to be completed by December 2007. The estimated cost of the project is approximately $119 million.

-

RG&E Dispute Settlement Related to NMP2 Exit Agreement

: In November 2001 RG&E and three other NMP2 joint owners, including Niagara Mohawk Power Corporation (Niagara Mohawk), sold their interests in NMP2 to Constellation Nuclear, LLC. In connection with the sale of NMP2, RG&E informed Niagara Mohawk that RG&E's payment obligations and rights to certain TCCs would cease according to the terms of an exit agreement executed by RG&E and Niagara Mohawk in June 1998. Niagara Mohawk disagreed with RG&E's position, claiming that RG&E must continue to make annual payments that were to decline from about $7 million per year in 2002 to $4 million per year in 2007, and remain at that level until 2043. In August 2001, RG&E filed a complaint asking the New York State Supreme Court, Monroe County, to find that, as a result of the sale of its interest in NMP2, RG&E has no further obligation to make payments under the exit agreement and that the TCCs to which RG&E was entitled under the exit agreement should be returned to and accepted by Niagara Mohawk.

In the first quarter of 2006, RG&E and Niagara Mohawk stayed the litigation and entered into confidential mediation with an ALJ appointed by the NYPSC. On June 29, 2006, the parties executed a settlement agreement that provides for RG&E's one-time payment of $34 million to Niagara Mohawk and further provides that RG&E retain the rights and obligations related to the TCCs until 2043, including the value accumulated to date of approximately $4 million. The settlement agreement was contingent upon the fulfillment of certain closing conditions, including FERC acceptance of an amendment to and restatement of the exit agreement. All of the necessary closing conditions were fulfilled, including a favorable judgment from the FERC and the lack of a negative finding by the Director of Accounting and Finance of the NYPSC, and RG&E made the required payment. In accordance with the 2001 settlement and order associated with the transfer of RG&E's share of NMP2 to Constellation Nuclear and RG&E's Electric Rate Agreement, RG&E adjusted its regulatory asset established as a result of the sale of NMP2 for the amount of the $34 million payment to Niagara Mohawk, which was offset by the accumulated TCC amount of approximately $4 million. The payment will also be adjusted by any future TCC amounts. RG&E's results of operations were not affected by the settlement of this dispute. The current amortization and recovery of this regulatory asset in rates remains unchanged.

Threatened Litigation for Russell Station

: In October 1999 RG&E received a letter from the New York State Attorney General's office alleging that RG&E may have constructed and operated major modifications to the Beebee and Russell generating stations without obtaining the required prevention of significant deterioration or new source review permits. The letter requested that RG&E provide the Attorney General's office with a large number of documents relating to this allegation. In January 2000 RG&E received a subpoena from the NYSDEC ordering production of similar documents. RG&E supplied documents and complied with the subpoena.

The NYSDEC served RG&E with a notice of violation in May 2000 alleging that between 1983 and 1987 RG&E completed five projects at Russell Station, and two projects at Beebee Station, which is currently shut down, without obtaining the appropriate permits. RG&E believes it has complied with the applicable rules and there is no basis for the Attorney General's and the NYSDEC's allegations. Beginning in July 2000 the NYSDEC, the Attorney General and RG&E had a number of discussions with respect to the resolution of the notice of violation. In October 2006 the Attorney General's office and the NYSDEC notified RG&E of their intention to file a complaint in federal court for violations at Russell Station unless a settlement can be reached.

Were the Attorney General and the NYSDEC to commence a Clean Air Act lawsuit against RG&E, they would need to demonstrate, among other things, that the challenged modifications to the Russell generating station cause an "increase" in emissions from the station. The issue of what constitutes the appropriate test for an emissions increase currently is before the United States Supreme Court in Environmental Defense v. Duke Energy Corporation, Docket No. 05-848. Oral argument was held on November 2006, and a decision is expected in the first half of 2007. RG&E, the NYSDEC and the Attorney General continue to discuss this matter and no suit has been filed to date. RG&E is not able to predict the outcome of this matter.

CMP Alternative Rate Plan

: In December 2005 CMP and the Maine Office of the Public Advocate filed with the MPUC a stipulation for an extension of CMP's ARP 2000. The stipulation was also supported by low-income customer advocates, and a coalition of industrial energy customers signed the stipulation agreement. The stipulation maintained the provisions of CMP's ARP 2000 and proposed a three-year extension with four additional items: (i) a 0.5% increase in the scheduled productivity offset of 2.75% for July 2006 and provided for productivity offsets

averaging 2% for 2008, 2009 and 2010, (ii) an additional $2.2 million in assistance for low-income customers annually starting in 2006, (iii) CMP agreed to educate its customers on the regional benefits of adjusting usage during peak hours and demand periods and also agreed to limit the promotion of increased usage during specified higher demand periods and (iv) CMP agreed to commit to investing an additional $25 million through 2010 for enhancements to the reliability, safety and security of its distribution system.

In February 2006 the MPUC approved that portion of the stipulation increasing assistance to low-income customers for one year. On April 28, 2006, the Staff of the MPUC filed its analysis and recommendations with the MPUC commissioners, opposing the stipulation other than the portion that was approved. CMP and the other stipulating parties responded to the Staff's recommendations in a brief filed on May 19, 2006. On June 5, 2006, the MPUC determined that the stipulation was not in the public interest unless substantially modified, and on June 21, 2006, the MPUC agreed to dismiss the proceeding at the request of the stipulating parties. CMP will file a proposal for a new alternative rate plan by May 1, 2007, to be effective January 1, 2008. In the interim, CMP continues to operate under the terms of ARP 2000.

CMP Electricity Supply Responsibility

: Under Maine statutes, CMP's customers can choose to arrange for competitive energy supply or take default supply under standard-offer service as arranged by the MPUC. The MPUC conducts periodic supply solicitations for standard-offer service by customer class. If the MPUC does not accept any competitive supply bid for a standard offer arrangement, the MPUC can mandate that CMP be a standard-offer provider of electricity supply service for retail customers and CMP would recover all costs of such an arrangement in rates. As of January 2007, the MPUC has approved standard-offer service arrangements for all of CMP's customer classes through competitive solicitation. The supply prices and terms of the arrangements vary by class, including a laddered three-year arrangement for residential and small commercial customers that solicits one-third of the supply each year and a six-month arrangement for medium and large commercial and industrial customers.

CMP Nuclear Costs

: CMP owns shares of stock in three companies that own nuclear generating facilities in New England that have been permanently shut down, and are decommissioned or in process of being decommissioned: Maine Yankee Atomic Power Company (38% ownership), Connecticut Yankee Atomic Power Company (6% ownership) and Yankee Atomic Electric Power Company (9.5% ownership). Each of the three facilities 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. The Yankee companies commenced litigation in 1998 charging that the federal government had breached the contracts it entered into with each of the Yankee companies in 1983 for spent nuclear fuel disposal. The contracts provided for the federal government to begin removing spent nuclear fuel from the Yankee companies, no later than January 31, 1998, in return for payments by each of the Yankee companies. Two federal courts found that the federal government breached its contracts with the Yankee companies and other utilities. A trial in the U.S. Court of Federal Claims to determine the monetary damages owed to the Yankee companies for the DOE's continued failure to remove spent nuclear fuel concluded in January 2005. The Yankee companies' individual damage claims are specific to each plant and include costs through 2010, the earliest year the DOE expects that it will begin removing fuel.

On September 30, 2006, the U.S. Court of Federal Claims issued a favorable ruling for the three Yankee companies in their litigation with the federal government over its failure to remove spent nuclear fuel from the three former nuclear power plant sites. In the ruling, Yankee Atomic was awarded $33 million in damages for costs through 2001, Connecticut Yankee was awarded $34 million for costs through 2001, and Maine Yankee was awarded $76 million for costs through 2002. CMP's sponsor-weighted share of the award is approximately $34 million. Since spent nuclear fuel continues to be stored at the sites, the Yankee companies will have the opportunity to recover more damages in future lawsuits. On December 4, 2006, the federal government appealed the decision, delaying payment of the damage awards. Any awards ultimately received will be credited to the Yankee companies' respective electric ratepayer-funded, decommissioning or spent fuel trust funds. CMP cannot predict the ultimate outcome of this matter.

Pursuant to a FERC approved settlement, in July 2004 Connecticut Yankee filed for FERC approval of a revised schedule of decommissioning charges to be collected from its wholesale customers, based on an updated estimate of decommissioning costs. Estimated decommissioning and long-term spent fuel storage costs for the period 2000 through 2023 increased by approximately $390 million in 2003 dollars and result in annual collections of $93 million from Connecticut Yankee's owners, including CMP. The revised estimate reflects increases in the projected costs for spent fuel storage, security, liability and property insurance and the fact that Connecticut Yankee had to take over all work to complete the decommissioning of the plant due to its termination of its contract with Bechtel, the turnkey decommissioning contractor, in July 2003. On August 11, 2006, Connecticut Yankee filed a settlement agreement supported by all parties, including the FERC trial staff, that resolved all of the issues contested and will allow Connecticut Yankee to collect the increased decommissioning costs. FERC approved the settlement agreement in November 2006. The revised decommissioning charges will be collected in wholesale rates effective January 1, 2007, until December 2015.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Nonutility Generation

: We expensed approximately $560 million for NUG power in 2006 and we estimate that our combined NUG power purchases will total $568 million in 2007, $392 million in 2008, $229 million in 2009, $84 million in 2010 and $85 million in 2011. CMP and NYSEG continue to seek ways to provide relief to their customers from above-market NUG contracts that state regulators ordered the companies to sign, and which, in 2006, averaged 10.2 cents per kilowatt-hour for CMP and 11.3 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's stranded cost rates and in NYSEG's rates through a nonbypassable wires charge. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

New England RTO

: In March 2004 the FERC issued an order that accepted a six-state New England RTO that CMP participates in and which is operated by ISO-NE and the New England transmission owners. The RTO began operations effective February 1, 2005. As an RTO, ISO-NE is responsible for the independent operation of the regional transmission system and regional wholesale energy market. The transmission owners retain ownership of their transmission facilities and control over their revenue requirements. The FERC also approved both a 50 basis point ROE incentive adder for regional transmission facilities subject to RTO control and a 100 basis point ROE incentive adder for new regional transmission facilities approved as part of the regional planning process. The New England transmission owners appealed the application of the adders to local facilities to the Circuit Court of Appeals for the District of Columbia. Other parties appealed the FERC's decision to grant the adders to regional facilities. On June 30, 2006, the Court denied the appeals and upheld the FERC's decisions. On October 31, 2006, the FERC issued an Opinion and

Order on Initial Decision establishing the ROE applicable to the RTO, including CMP's transmission system. The October 31 order adopts a base-level ROE of 10.2 percent, with three adjustments as follows: a 50 basis point incentive for RTO participation; a 100 basis point incentive for new transmission investment; and a 74 basis point adjustment reflecting updated bond data, as applicable to the period commencing with the date of the order. The resulting ROEs for existing regional transmission facilities were 10.7 percent for the period February 1, 2005, through October 31, 2006, and are 11.4 percent for the going-forward period.

The ROEs that will apply to post-2003 regional transmission facilities approved as part of the regional reliability planning process will include an incremental 100 basis point adder, and are 11.7 percent prior to the date of the order, and 12.4 percent for the going-forward period. Several parties have filed for rehearing of the order and can appeal the final order. The New England transmission owner filing parties submitted a filing in compliance with the order on December 21, 2006 to establish a refund and billing procedure as required by the final Order. On February 6, 2007, several parties filed a late protest to this compliance filing. CMP cannot predict the outcome of these proceedings.

Locational Installed Capacity Markets

: In 2003 the FERC required ISO-NE to file a proposed mechanism to implement, by January 1, 2006, location or deliverability requirements in the installed capacity or resource adequacy market to ensure that generators that provide capacity within areas of New England are appropriately compensated for reliability. In response, in 2004 ISO-NE developed and filed with the FERC a market proposal based on an administratively set demand curve (previously referred to as locational installed capacity or LICAP). In June 2005 the FERC ALJ issued an initial decision, essentially adopting the ISO-NE market proposal, with minor modifications.

-

CMP and other parties that oppose the ISO-NE market proposal filed exceptions to the recommended decision in July 2005. The Energy Policy Act of 2005 included a "sense of Congress" provision to the effect that the FERC should carefully consider the objections of the New England states to the proposal in the recommended decision. Following oral arguments, the FERC granted the request to conduct settlement discussions to consider alternatives. Settlement discussions began in November 2005 and in January 2006 the settlement ALJ reported to the FERC that most of the parties had reached an agreement in principle on an alternative. The alternative would provide fixed transitional capacity payments from 2006 until 2010 and provide capacity payments based on a Forward Capacity Market Auction thereafter. CMP opposed this settlement agreement because of the cost of the transition payments to electric customers in Maine. The ISO-NE and a majority of New England Power Pool (NEPOOL) participants supported the settlement agreement. That alternative has been filed with the FERC as a component of a comprehensive settlement agreement.

The MPUC, among other parties, filed comments opposing the settlement agreement, because the proposal could have an adverse effect on Maine's economy by increasing its generation supply rates, including standard offer rates, by an estimated 5% to 10%. On June 15, 2006, the FERC issued an order accepting the settlement agreement without modification. The MPUC and other parties opposed to the settlement agreement filed a request with the FERC asking it to reconsider its June 15 order. On October 31, 2006, the FERC issued an Order on Rehearing and Clarification denying requests for rehearing and affirming its approval of the settlement agreement. With the FERC's denial of the rehearing requests, the resulting increased costs associated with regional installed capacity have been reflected in

Maine consumers' generation supply rates since December 2006. Several parties, including the MPUC, have filed notices of appeal in the US Circuit Court of Appeals, seeking to overturn the FERC's orders approving the settlement agreement. CMP cannot predict the outcome of these proceedings.

MPUC Inquiries into Long-Term Utility Contracting and Continued Participation in New England RTO

: Maine lawmakers enacted legislation in 2005 that requires the MPUC to conduct two inquiries. The first concerns whether or not CMP and other Maine electric utilities should continue to participate in the New England RTO, as operated by the ISO-NE. In this inquiry, the MPUC issued an interim report to the Maine Legislature on January 16, 2007, reporting its preliminary findings: inequities exist in the current cost allocation system of the ISO-NE tariff; no insurmountable legal, economic or technical barriers preclude withdrawal from the ISO-NE; and reasonable alternatives exist. The MPUC has begun the next phase of this inquiry in which three options will be explored: altering the transmission cost allocation formula; exiting the RTO and creating a state-wide independent transmission company; or joining with New Brunswick and other Maritime provinces to create a Maine-Canada market. The MPUC has set a June 2007 target date for a draft report to the legislature containing recommendations for further action.

-

The second inquiry concerns regional energy markets and generation deregulation. The MPUC conducted an initial inquiry into the development of a Maine electric resource adequacy plan and the use of long-term generating capacity contracts between utilities and capacity suppliers and developed provisional long-term contracting rules and the first report on resource adequacy, which were submitted to the legislature for further action in early 2007. Because the proposed long-term contracting rules are considered major, substantive rules, the Maine Legislature must vote on their adoption.

CMP will continue to participate in the MPUC and subsequent legislative proceedings and cannot predict the outcome of the inquiries.

Natural Gas Delivery Rate Overview

Our natural gas delivery business consists of our regulated natural gas transportation, storage and distribution operations in New York, Connecticut, Massachusetts and Maine. The natural gas industry is regulated by various state and federal agencies, including state utility commissions. All of our natural gas utilities have a natural gas supply charge or a purchased gas adjustment clause to defer and recover actual natural gas costs. The following is a brief overview of the current rate agreements in effect for each of our natural gas utilities.

Natural Gas Rate Plans

: NYSEG's Natural Gas Rate Plan, which became effective October 1, 2002, freezes overall delivery rates through December 31, 2008, and contains an earnings-sharing mechanism, a weather normalization adjustment mechanism and a gas cost incentive mechanism. The earnings-sharing mechanism requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 12.5% through 2008. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $250 million. No sharing occurred in 2006, 2005 or 2004.

RG&E's current rates were established by the 2004 Natural Gas Rate Agreement, which addresses RG&E's natural gas rates through 2008. Key features of the Natural Gas Rate Agreement include freezing natural gas delivery rates through December 2008, except for the implementation of a natural gas merchant function charge to recover approximately $7 million annually beginning May 1, 2004. The Natural Gas Rate Agreement also implemented a weather normalization adjustment to protect both customers and RG&E from fluctuating revenues due to swings in temperature outside a normal range, and a gas cost incentive mechanism to provide a means of sharing with customers any future gas supply cost savings that RG&E achieves. An earnings-sharing mechanism was established to allow customers and shareholders to share equally in earnings above a 12.0% ROE target. No sharing occurred in 2006, 2005 or 2004.

SCG's current rates became effective on January 1, 2006, pursuant to a settlement agreement that is in effect through December 31, 2007. The total increase in revenue requirements for firm rates was set at 8.4% or about $26.7 million and included amounts for recovery of previously deferred costs including bad debts.

CNG's IRP expired on September 30, 2005, and its rates have continued in effect since then, but the earnings sharing mechanism, the rate stay-out commitment and the exogenous cost provision were no longer applicable. On September 29, 2006, CNG filed for new rates to become effective on April 1, 2007. On December 21, 2006, CNG and other participants in the proceeding filed a settlement agreement with the DPUC for an increase of $15.5 million that would be in effect through March 31, 2008. (See CNG Regulatory Proceeding.)

-

Berkshire Gas' current rate plan is a 10-year rate plan that went into effect on February 1, 2002, and runs through January 31, 2012, with a mid-period review in 2007. The plan has no ROE cap and has an annual inflationary rate adjustment that is determined based on the gross domestic product minus 1% as a productivity offset. The adjustment is made on September 1st each year. Berkshire Gas does not believe the mid-period review will result in any significant changes to its rate plan.

Natural Gas Delivery Business Developments

Natural Gas Supply Agreements

: Our natural gas companies - NYSEG, RG&E, SCG, CNG, Berkshire Gas and MNG - each have a three-year strategic alliance with BP Energy Company ending on March 31, 2007, that gives them the right to acquire natural gas supply and optimizes transportation and storage services. We are exploring our options for a new alliance.

CNG Regulatory Proceeding

: On March 21, 2006, the DPUC notified CNG that it had initiated a general rate review of CNG pursuant to Connecticut General Statutes, which state that the DPUC must conduct a financial review or require a rate case every four years. On September 29, 2006, CNG submitted a general rate filing, requesting a net rate increase of $28.2 million, or 7.9%, in base delivery revenues effective April 1, 2007, based on an 11.0% ROE. The requested increase includes $6.7 million for increased bad debt expense, including a hardship program, $5.6 million for sharing of achieved management efficiencies and $4.3 million to offset lower normalized customer usage.

On December 21, 2006, CNG and the OCC filed with the DPUC a proposed Settlement Agreement in which the parties have agreed to a net increase in firm revenues of $15.5 million (4.2% of total firm revenues), and a 10.1% ROE. CNG has also agreed to freeze its base distribution rates for a period of at least 30 months, until October 2009, to implement an automated meter reading system by July 2008, and to a non-firm delivery margin threshold of $8.6 million with sharing of 86% to customers and 14% to shareholders. A final decision by the DPUC is expected in April 2007.

Manufactured Gas Plant Remediation Recovery

: RG&E and NYSEG independently began cost contribution actions against FirstEnergy Corp. (formerly GPU, Inc.) in federal district court; RG&E in the Western District of New York in August 2000 and NYSEG in the Northern District of New York in April 2003. The actions are for both past and future costs incurred for the investigation and remediation of inactive manufactured gas plant sites. Discovery is ongoing in both actions. A trial date for the RG&E action has been set for the fourth quarter of 2007. Any proceeds from these actions will go to customers. RG&E and NYSEG are unable to predict the outcome of these actions at this time.

Environmental Insurance Settlements

: In 2005 we served demands on three of our liability insurance carriers seeking coverage for environmental investigation and clean-up costs incurred at three former manufactured gas plant sites located in Massachusetts. In 2006 we settled claims against two carriers for substantial cash payments from each. We are still in negotiations with the third carrier and cannot, at this time, predict the results of these negotiations. Pursuant to Massachusetts regulations, we are allowed to retain a share of these settlement proceeds for shareholders.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

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 our Consolidated Financial Statements for explanations about these new accounting standards and when they will become or became effective.

Contractual Obligations and Commercial Commitments

At December 31, 2006, our contractual obligations and commercial commitments are:

	Total	2007	2008	2009	2010	2011	After 2011
(Thousands)							
Contractual Obligations							

Long-term debt[1]	$7,521,068	$497,028	$318,878	$365,525	$467,371	$407,927	$5,464,339
Capital lease obligations[1]	37,116	3,486	3,486	3,513	3,513	2,791	20,327
Operating leases	87,762	13,452	13,071	11,761	11,664	10,494	27,320
Nonutility generator power purchase obligations	1,821,553	567,815	392,057	229,209	83,586	84,927	463,959
Nuclear plant obligations	229,354	28,878	25,240	13,543	12,631	3,868	145,194
Unconditional purchase obligations:							
Electric	2,032,368	373,401	290,453	296,135	311,961	279,568	480,850
Natural gas	212,320	86,017	71,276	27,284	16,589	9,864	1,290
Pension and other postretirement benefits[2]	2,252,779	184,804	193,507	203,112	213,599	225,162	1,232,595
Other long-term obligations	7,179	3,727	1,621	885	596	267	83
Total Contractual Obligations	$14,201,499	$1,758,608	$1,309,589	$1,150,967	$1,121,510	$1,024,868	$7,835,957

(1) Amounts for long-term debt and capital lease obligations include future interest payments. Future interest payments on variable-rate debt are determined using established rates at December 31, 2006.
(2) Amounts are through 2016 only.
(3) The above table excludes our regulatory liabilities, deferred income taxes, asset retirement obligation and environmental remediation costs because the related future cash flows are uncertain. See Item 8 - Notes 6, 7, 9 and 14 to our Consolidated Financial Statements for additional information regarding our financial commitments at December 31, 2006.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Critical Accounting Policies

In preparing our financial statements in accordance with accounting principles generally accepted in the United States of America, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. Our most critical accounting policies include the effects of utility regulation on our financial statements, the estimates and assumptions used to perform our annual impairment analyses for goodwill and other intangible assets, to calculate pension and other postretirement benefits and to estimate unbilled revenues and the allowance for doubtful accounts.

Regulatory Assets and Liabilities

: Statement 71 allows companies that meet certain criteria to capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future periods. Those companies record, as regulatory liabilities, obligations to refund previously collected revenue or obligations to spend revenue collected from customers on future costs.

We believe our public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electric and natural gas operations in New York, Maine, Connecticut and Massachusetts; however, we cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC, DTE or FERC will have on their ability to continue to do so. If our public utility subsidiaries can no longer meet the criteria of Statement 71 for all or a separable part of their regulated operations, they may have to record as an expense or as revenue certain regulatory assets and regulatory liabilities.

Approximately 90% of our revenues are derived from operations that are accounted for pursuant to Statement 71. The rates our operating utilities charge their customers are set under cost basis regulation reviewed and approved by each utility's governing regulatory commission.

Goodwill and Other Intangible Assets

: We do not amortize goodwill or intangible assets with indefinite lives. We test both goodwill and intangible assets with indefinite lives for impairment at least annually and amortize intangible assets with finite lives and review them for impairment. Impairment testing includes various assumptions, primarily the discount rate and forecasted cash flows. We conduct our impairment testing using a range of discount rates representing our marginal, weighted-average cost of capital and a range of assumptions for cash flows. Changes in those assumptions outside of the ranges analyzed could have a significant effect on our determination of an impairment. We had no impairment in 2006 of our goodwill or intangible assets with indefinite lives. (See Item 8 - Note 4 to our Consolidated Financial Statements and Note 3 to RG&E's Financial Statements.)

Pension and Other Postretirement Benefit Plans

: We have pension and other postretirement benefit plans covering substantially all of our employees. In accordance with Statement 87 and Statement 106, the valuation of benefit obligations and the performance of plan assets are subject to various assumptions. The primary assumptions include the discount rate, expected return on plan assets, rate of compensation increase, health care cost inflation rates, mortality tables, expected years of future service under the pension benefit plans and the methodology used to amortize gains or losses.

Energy East Corporation

Assumptions are based on our best estimates of future events using historical evidence and long-term trends. Changes in those assumptions, as well as changes in the accounting standards related to pension and postretirement benefit plans, could have a significant effect on our noncash pension income or expense or on our postretirement benefit costs. As of December 31, 2006, we increased the discount rate from 5.50% to 5.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rate was determined 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. (See Item 7 - MD&A - Other Market Risk, and Item 8 - Note 14 to our Consolidated Financial Statements and Note 12 to RG&E's Financial Statements.)

Unbilled Revenues

: 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. (See Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.)

Allowance for Doubtful Accounts

: 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. (See Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.)

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Liquidity and Capital Resources

Cash Flows

The following table summarizes our consolidated cash flows for 2006, 2005 and 2004.

Year Ended December 31,	2006	2005	2004
(Thousands)			

Operating Activities			
Net income	$259,832	$256,833	$229,337
Noncash adjustments to net income	419,196	422,635	431,700
Changes in working capital	(198,307)	(95,256)	(233,246)
Other	(101,227)	(83,940)	(88,691)
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)
Current investments available for sale, net	172,925	(57,270)	(135,655)
Other	7,547	20,133	1,600
Net Cash (Used in) Provided by Investing Activities	(227,759)	(368,431)	96,953
Financing Activities			
Net issuance of common stock	(5,764)	(3,838)	(2,988)
Net (repayments of) increase in debt and preferred stock of subsidiaries	(5,258)	30,908	(333,095)
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

Operating Activities Cash Flows

: Net cash provided by operating activities was $379 million in 2006 compared to $500 million in 2005 and $339 million in 2004. The major items that contributed to the $121 million decrease in cash provided by operating activities for 2006 were:

- A reduction in accounts payable and accrued liabilities primarily due to payments for natural gas and electricity purchases and to refunds of amounts previously held on deposit that reduced cash flow by $339 million, and
- The payment of $34 million by RG&E to resolve a dispute with Niagara Mohawk. (See RG&E Dispute Settlement Related to NMP2 Exit Agreement.)

-

Those decreases in cash flow were partially offset by:

- A reduction in receivables that increased cash flow by $123 million,
- A reduction in inventory due to lower natural gas prices that increased cash flow by $88 million, and
- Lower pension contributions that increased cash flow by $54 million.

The $161 million increase in cash provided by operating activities for 2005 was primarily due to:

- Increased accounts payable and accrued liabilities of $103 million primarily for the purchase of electricity and natural gas at higher prices than in the prior year.
- A decrease in the amount of taxes paid in the current year of $93 million, primarily due to taxes paid in 2004 for the sale of Ginna.
- A decrease of $35 million in customer refunds related to the proceeds from the sale of Ginna in 2004. RG&E refunded $60 million in 2004 and $25 million in 2005.

Those increases in cash flow were partially offset by:

- Increased expenditures of $40 million to replenish natural gas inventories,

- An increase of $37 million due to higher accounts receivable resulting from higher prices, and
- An increase of $35 million in pension contributions.

Investing Activities Cash Flows

: Net cash used in investing activities was $228 million in 2006 compared to $368 million in 2005 and net cash provided by investing activities of $97 million in 2004. The $140 million decrease in 2006 was primarily due to the liquidation of current investments available for sale. The $465 million change in 2005 was primarily due to effects of the sale of Ginna in 2004.

Utility capital spending totaled $408 million in 2006, $331 million in 2005 and $299 million in 2004, including nuclear fuel for RG&E in 2004. Capital spending in all three years was financed principally with internally generated funds, and was primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates, new customer care systems for NYSEG and RGE, and the RG&E transmission project.

Utility capital spending is projected to be $496 million in 2007, the majority of which is expected to be paid for with internally generated funds and will be primarily for the same purposes described above, except for the now completed customer care systems for NYSEG and RG&E. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

Cash flows from investing activities include proceeds from the liquidation of auction rate securities, which are recorded as current investments available for sale. We use auction rate securities in a manner similar to cash equivalents and the amount invested in such securities will increase as short-term funds are available. Our investments in auction rate securities have decreased during the year as a result of the operational activities discussed above.

Financing Activities Cash Flows

: Net cash used in financing activities was $178 million in 2006 compared to $123 million in 2005 and $472 million in 2004. The $55 million increase in 2006 was primarily due to lower net issuance of long-term debt securities than in 2005. The $349 million decrease in 2005 was primarily the result of lower debt redemptions than in 2004 when funds were available from the sale of Ginna.

Capital Structure at December 31,	2006	2005	2004
Long-term debt[1]	57.1%	57.0%	57.2%
Short-term debt[2]	1.6%	1.7%	3.1%
Preferred stock	0.3%	0.4%	0.7%
Common equity	41.0%	40.9%	39.0%
	100.0%	100.0%	100.0%

[1] Includes current portion of long-term debt
[2] Includes notes payable

The financing activities discussed below include those activities necessary for the company and its principal subsidiaries to maintain adequate liquidity and improve credit quality and ensure access to capital markets. Activities include minimal common stock issuances in connection with our Investor Services Program and employee stock-based compensation plans, new short-term facilities and various medium-term and long-term debt transactions.

Our equity financing activities during 2006 and early 2007 included:

- Raising our common stock dividend 3.4% in October 2006 to a new annual rate of $1.20 per share.
- Repurchasing 250,000 shares of our common stock in February 2006, primarily for grants of restricted stock.
- Awarding 273,733 shares of our common stock in 2006, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.75 per share of common stock awarded.
- Issuing 204,235 shares of our common stock in 2006, at an average price of $24.21 per share, through our Investor Services Program. The shares were original issue shares.
- Repurchasing 350,000 shares of our common stock in January 2007, primarily for grants of restricted stock.
- Awarding 296,145 shares of our common stock in February 2007, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.76 per share of common stock awarded.

In January 2006 CMP issued $10 million of Series F medium-term notes at 5.27%, due in 2016, and $30 million of Series F medium-term notes at 5.30%, due in 2016, to refinance maturing debt.

In April 2006 NYSEG issued $12 million of Series 2006A tax-exempt multi-mode bonds, due in 2024 at an initial interest rate of 3.10%, which is presently reset weekly in an auction process, to refinance $12 million of maturing debt that had an interest rate of 6%.

In July 2006, we redeemed all of our 8 1/4% junior subordinated debt securities at par and expensed approximately $11 million of unamortized expense in July 2006 in connection with the redemption. $10 million of this amount was related to the issuance of the associated trust preferred securities. The redemption was 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. (See Item 8 - Note 6 to our Consolidated Financial Statements.) We settled the hedges we had entered into in connection with the refinancing at a gain of approximately $15 million, which we will amortize over the life of the new debt.

In August 2006, we issued an additional $250 million of unsecured long-term debt at 6.75%, due in 2036. We used substantially all of the proceeds to redeem $232 million of 5.75% notes that were scheduled to mature in November 2006. We settled the hedges we had entered into in connection with the refinancing at a gain of approximately $8 million, which we will amortize over the life of the new debt.

In December 2006 NYSEG issued $100 million of senior unsecured notes at 5.65%, due in 2016. A portion of the proceeds was used to refund short-term debt that was issued to refinance a $25 million tax-exempt note that matured on December 1, 2006, and to fund the $77 million customer refund that will be made by the end of April 2007.

Available Sources of Funding

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. In June 2006 we extended our two revolving credit facilities for one year. Both facilities now 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 December 31, 2005.

We use commercial paper and drawings on our credit facilities (see above) 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.

We filed a shelf registration statement with the SEC in June 2003 to sell up to $1 billion in an unspecified combination of debt, preferred stock, common stock and trust preferred securities. We plan to use the net proceeds from the sale of securities under this shelf registration, if any, for general corporate purposes. We currently have $305 million available under the shelf registration statement.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Market Risk

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 our 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. We handle market risks in accordance with established policies, which may include various offsetting, nonspeculative derivative transactions. (See Item 8 - Note 1 to our Consolidated Financial Statements.)

The financial instruments we hold or issue are not for trading or speculative purposes. Our 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

: We are exposed to risk resulting from interest rate changes on variable-rate debt and commercial paper. 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 those agreements as adjustments to the interest expense of the specific debt issues. After giving effect to those agreements we estimate that, at December 31, 2006, a 1% change in average interest rates would change our annual interest expense for variable-rate debt by about $5 million. Pursuant to its current rate plans, RG&E defers any changes in variable-rate interest expense. (See Item 8 - Notes 6, 7 and 11 to our Consolidated Financial Statements and Notes 5, 6 and 10 to RG&E's Financial Statements.)

We also use derivative instruments to mitigate risk resulting from interest rate changes on anticipated future financings, and amortize amounts paid and received under those instruments to interest expense over the life of the corresponding 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 utility industries. We manage 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 our commodity price exposure, but do not completely eliminate it.

NYSEG and RG&E offer their 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, NYSEG's and RG&E's electric customers chose their supply options for 2007. The table below shows the percentages of load that are projected to be served under the various commodity supply options for 2007.

	NYSEG	RG&E
Fixed Price Option	17%	21%
Variable Price Option	45%	29%
Energy Service Company Option	38%	50%

NYSEG's and 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 effectively combines delivery and supply service at a fixed price. NYSEG and RG&E use electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity required to serve customers who select the fixed rate option. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. Owned electric generation and long-term supply contracts reduce NYSEG's exposure, and significantly reduce RG&E's exposure, to market fluctuations for procurement of their fixed rate option electricity supply.

As of February 15, 2007, the portion of expected load for fixed rate option customers not supplied by owned generation or long-term contracts is 100% hedged for NYSEG for on-peak and off-peak periods in 2007. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change NYSEG's earnings less than $150 thousand for NYSEG in 2007. RG&E expects to meet its fixed price load obligations in 2007 with owned generation or long-term supply contracts. The percentage of NYSEG's and RG&E's hedged load is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

Other comprehensive income associated with our financial electricity contracts for the year ended December 31, 2006, was $7 million, reflecting a decrease of $162 million as compared to December 31, 2005. The decrease is primarily a result of wholesale market price changes for electricity and the settlement of positions in 2006. Other comprehensive income for 2006 will have no effect on future net income because we only use financial electricity contracts to hedge the price of our electric load requirements for customers who have chosen a fixed price option.

All of our natural gas 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 in order to provide price stability to customers. We include 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. We record changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities.

Energetix and NYSEG Solutions offer retail electric and natural gas service to customers in New York State and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of February 15, 2007, the energy marketing subsidiaries expected fixed price load was 100% hedged for 2007. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change earnings less than $20,000 in 2007. The percentage of hedged load for the energy marketing subsidiaries is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

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.

Other Market Risk

: Our 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 us to recognize increased or decreased pension income or expense. Our pension income would change by approximately $7 million if our expected return on plan assets were to change by 1/4% and by approximately $6 million if our discount rate were to change by 1/4%. Under RG&E's Electric and Natural Gas Rate Agreements and under NYSEG's natural gas rate plan, we defer changes in pension income resulting from changes in market conditions. (See Item 8 - Note 14 to our Consolidated Financial Statements and Note 12 to RG&E's Financial Statements.)

Results of Operations

Earnings per Share

	2006	2005	2004
(Thousands, except per share amounts)			
Income from Continuing Operations	$259,832	$256,833	$237,621
Net Income	$259,832	$256,833	$229,337
Average Common Shares Outstanding, basic	146,962	146,964	146,305
Earnings per Share from Continuing Operations, basic	$1.77	$1.75	$1.63
Earnings per Share, basic	$1.77	$1.75	$1.57

Comparing 2006 to 2005

: Earnings per share from continuing operations, basic for 2006 increased two cents compared to 2005. The major increases in earnings per share were:

- 18 cents due to higher margins on electricity sales, primarily reflecting lower accruals under various earnings-sharing mechanisms,
  - 7 cents in lower income tax expense reflecting 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,
  - 4 cents resulting from the environmental insurance settlements in the fourth quarter of 2006,
  - 5 cents due to the termination of SGF's operations in 2005, including 4 cents from the writedown of the assets, and
  - 2 cents due to reductions in various operating and maintenance expenses.

-

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Those increases were partially offset by decreases in earnings per share of:

- 11 cents resulting from higher storm and flood costs,

- 7 cents resulting from higher bad debt expense, including 4 cents for amounts that were previously deferred and began to be recovered as part of a rate increase for SCG effective January 1, 2006,
- 6 cents for higher interest expense resulting from higher rates on short-term and variable rate debt, and higher carrying costs on regulatory liabilities,
- 5 cents for the recognition of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and associated trust preferred securities in July 2006,
- 4 cents in increased depreciation expense, due to placing NYSEG's customer care system into service in the first quarter of 2006,
- 2 cents from lower margins on natural gas sales due to warmer weather. This amount would have been higher except for the SCG rate increase effective January 1, 2006, and the effect of weather normalization mechanisms.

Comparing 2005 to 2004

: Earnings from continuing operations, basic for 2005 increased 12 cents per share compared to 2004. The major increases in earnings per share were:

- 21 cents due to higher margins on electric sales under electric commodity programs for New York customers,

- 17 cents resulting from a 3% increase in electric deliveries, and
- 4 cents resulting from increased natural gas margins. The increase resulted primarily from increased sales to interruptible customers and RG&E's adoption of a natural gas merchant function charge in 2004.

Those increases were partially offset by decreases in earnings per share of:

- 19 cents per share resulting from higher operating and maintenance expenses, including approximately 5 cents for storm-related repairs and maintenance, 9 cents for increases in allowances for doubtful accounts, 2 cents for higher regional network services transmission costs and 4 cents for medical and other benefits costs. The higher operating and maintenance expenses were partially offset by a decrease of 8 cents for lower stock option expenses. Stock option expense in 2005 included a one cent-per-share charge for the adoption of Statement 123(R),
- 4 cents per share from the termination of SGF's operations and the writedown of assets, and
- 7 cents for the one-time effects from the sale of Ginna and the approval of RG&E's Electric and Natural Gas Rate Agreements that increased earnings in 2004. The one-time effects included the flow-through of excess deferred taxes and ITCs and the elimination of certain reserves established pending regulatory treatment.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Energy Delivery

Revenues for our utility operating companies are highly dependent upon the volume of deliveries of electricity and natural gas. We have regulatory mechanisms in place to provide recovery of certain costs, including stranded costs and natural gas purchase costs, independent of sales volume, and some of our natural gas companies have weather normalization clauses that mitigate the effect of delivery volume changes due to weather. Changes in delivery volume can nevertheless have a significant effect on our results of operations, financial position and cash flows.

Electric revenues are also dependent upon the volume of sales of electricity to retail customers under Voice Your Choice commodity programs offered by our New York utilities. The cost of the electricity sold to retail customers is either recovered as a passthrough or hedged to substantially eliminate the risk of price volatility. Changes in commodity sales volume, however, can have a significant effect on our results of operations and cash flows.

Percentage increases (decreases) in energy delivery volumes and electric commodity sales volumes compared to the prior year are:

	Electricity Deliveries		Natural Gas Deliveries	
	2006	2005	2006	2005
(Thousands)				
Residential	(4%)	6%	(12%)	(3%)
Commercial	(2%)	3%	(11%)	1%
Industrial	(3%)	(2%)	(11%)	(3%)
Other	(2%)	2%	17%	(2%)
Transportation of customer-owned natural gas	NA	NA	(7%)	(1%)
Total Retail	(3%)	3%	(8%)	(2%)
Wholesale	(2%)	21%	(87%)	(45%)
Total Deliveries	(2%)	7%	(8%)	(2%)
Electricity commodity sales	(7%)	(8%)	NA	NA

NA - not applicable

Several factors influence the volume of energy deliveries. The major factor is weather. In 2006 winter temperatures were significantly warmer than normal. The effects of warmer or colder winter weather are especially significant for our natural gas companies. We estimate that for 2006, 2% of the 3% decline in retail electricity deliveries and 6% of the 8% decline in retail natural gas deliveries was the result of warmer winter weather. Weather conditions for New York and New England for the past three years are summarized below.

-

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Weather Conditions

	2006	2005	2004	Normal
New York				
Heating-degree days	5,991	6,870	6,983	6,974
(Warmer) colder than prior year	(13%)	(2%)		
(Warmer) colder than normal	(14%)	(2%)		

Cooling-degree days	562	748	324	493
(Cooler) warmer than prior year	(25%)	131%		
(Cooler) warmer than normal	14%	52%		
New England				
Heating-degree days	5,447	6,229	6,260	6,315
(Warmer) colder than prior year	(13%)	(1%)		
(Warmer) colder than normal	(14%)	(1%)		
Cooling-degree days	444	506	250	388
(Cooler) warmer than prior year	(12%)	102%		
(Cooler) warmer than normal	14%	30%		

Operating Results for the Electric Delivery Business

	2006	2005	2004
(Thousands)			
Operating Revenues			
Retail	$2,254,003	$2,250,105	$2,191,500
Wholesale	554,300	568,746	402,122
Other	214,734	150,707	187,700
Total Operating Revenues	3,023,037	2,969,558	$2,781,322
Operating Expenses			
Electricity purchased and fuel used in generation	1,467,068	1,457,746	1,321,081
Other operating and maintenance expenses	715,219	672,595	667,503
Depreciation and amortization	187,587	178,806	196,782
Other taxes	148,589	143,359	154,038
Gain on sale of generation assets	-	-	(340,739)
Deferral of asset sale gain	-	-	228,785
Total Operating Expenses	2,518,463	2,452,506	2,227,450
Operating Income	$504,574	$517,052	$553,872

Operating Revenues

: The $53 million increase in operating revenues for 2006 was primarily the result of:

- An increase of $57 million due to higher commodity prices for retail electric energy sold by NYSEG and RG&E under various commodity options where they provide supply,
- An increase of $60 million in average delivery prices resulting from a transmission rate increase at CMP and higher transition charges for NYSEG and RG&E,
- An increase of $53 million resulting from lower accruals for earnings sharing including $14 million in the first quarter of 2006 for the finalization of actual earnings-sharing amounts for 2005 per NYSEG's and RG&E's annual compliance filings, and
- An increase of $31 million in other revenues primarily for accruals to recover actual purchase power costs, including $25 million for higher Ginna-related costs.

-

Energy East Corporation

Those increases were partially offset by:

- A decrease of $78 million resulting from a 7% reduction in sales volume under the New York utilities' Voice Your Choice commodity programs where they provide supply,
- A decrease of $22 million in wholesale sales resulting from a 2% decline in wholesale volume,
- A decrease of $12 million in other revenue including $6 million related to a NUG incentive at CMP and $6 million of accruals for transmission congestion costs, both recorded in 2005, and
- A decrease of $35 million resulting from a 3% decline in retail deliveries, about 2% of which was caused by cooler summer temperatures and warmer winter weather. Heating degree days declined 13% in 2006. The other 1% of the decline was largely attributable to the expiration of a major NUG contract for CMP, since the NUG is now using electricity previously sold to CMP to meet its own load requirements.

The $188 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $73 million from increases in market prices for electric energy sold by NYSEG and RG&E under commodity options where they provide supply,
- An increase of $168 million in wholesale revenues, which included $100 million from increased wholesale sales by NYSEG and RG&E, $29 million from higher prices on those sales and $39 million as a result of higher prices on the sale of CMP's NUG entitlements, effective March 1, 2005,
- An increase of $42 million resulting from a 3% increase in retail deliveries. About half of this increase resulted from warmer summer weather and the remainder resulted from general economic conditions, and
- An increase of $36 million in other electric revenues, including $6 million from CMP's NUG contract restructuring incentive and the remainder primarily from accruals to reflect actual generating and purchase power costs.

Those increases were partially offset by:

- A decrease of $102 million resulting from lower transition charges. The transition charge reflects the difference between the market price of electricity and the prices set by our long-term electricity supply contracts, and decreases as market prices increase, and
- A decrease of $28 million as a result of higher accruals for earnings sharing under NYSEG's and RG&E's electric rate plan provisions.

Operating Expenses

: The $66 million increase in operating expenses for 2006 was primarily the result of:

- An increase of $9 million in purchased power costs resulting from a $39 million increase for higher wholesale electricity market prices, and $25 million for higher purchased power costs for RG&E related to Ginna purchases, partially offset by a $55 million decrease due to the expiration of a major NUG contract in 2006,
- An increase of $43 million in operating and maintenance costs, including $26 million for storm restoration, $9 million for a write-off resulting from the August 2006 NYSEG rate decision and

$9 million for higher bad debt expense,
- An increase of $9 million in depreciation resulting largely from NYSEG's new customer care system, and
- An increase of $5 million in other taxes.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

The $225 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $112 million as a result of the regulatory treatment in 2004 of RG&E's gain on the sale of Ginna, which included RG&E's recognition of a $341 million pretax gain partially offset by the after-tax deferral of the gain of $229 million,
- A net increase of $1 million in operating expenses as a result of the sale of Ginna, reflecting an increase in purchased power costs of $63 million, substantially offset by decreases of $37 million in other operating and maintenance expenses, $21 million in depreciation and $4 million in other taxes,
- An increase of $75 million in power purchases largely resulting from increased wholesale sales and higher market prices for electric supply purchased for the New York electric commodity customers,
- An increase of $10 million due to certain credits to other operating expenses that resulted from RG&E's Electric Rate Agreement and reduced expenses in 2004, and
- Increases in various other operating and maintenance expenses, excluding Ginna, totaling $27 million. Higher storm costs accounted for approximately $11 million of that increase, higher transmission-related expenses accounted for an additional $6 million, higher uncollectible expense accounted for $9 million and increased medical and other benefits accounted for $8 million. Lower stock option expense reduced electric operating expenses by $10 million.

Operating Results for the Natural Gas Delivery Business

	2006	2005	2004
(Thousands)			
Operating Revenues			
Retail	$1,676,525	$1,764,235	$1,534,900
Wholesale	563	643	182
Other	20,513	18,669	14,068
Total Operating Revenues	1,697,601	1,783,547	1,549,150
Operating Expenses			
Natural gas purchased	1,079,980	1,161,059	952,806
Other operating and maintenance expenses	246,727	246,339	231,182
Depreciation and amortization	86,728	85,050	88,998

Other taxes	95,390	98,589	93,500
Total Operating Expenses	1,508,825	1,591,037	1,366,486
Operating Income	$188,776	$192,510	$182,664

Operating Revenues

: The $86 million decrease in operating revenues for 2006 was primarily the result of:

- A decrease of $146 million as a result of a 9% decrease in delivery volumes excluding transportation, largely due to warmer winter weather and customer conservation. Heating degree days in 2006 declined 13% compared to 2005 and caused approximately two-thirds of the sales decline.

-

That decrease was partially offset by:

- An increase of $24 million primarily as a result of higher market prices for natural gas that were passed on to customers,
- An increase of $20 million due to higher base rates for SCG effective January 1, 2006, and
- An increase of $16 million resulting from weather normalization mechanisms.

The $234 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $244 million as a result of higher prices of purchased natural gas that were passed on to customers, and
- An increase of $23 million in other natural gas revenues resulting primarily from higher interruptible sales.

Those increases were partially offset by:

- Lower retail deliveries of $33 million due in part to warmer weather but also reflecting economic conditions including higher market prices for natural gas.

Operating Expenses

: The $82 million decrease in operating expenses for 2006 was primarily the result of:

- A reduction of $100 million due to lower volumes of natural gas sold, and
- Reductions in various operating and maintenance expense items totaling $9 million.

Those decreases were partially offset by:

- An increase of $18 million due to higher market prices for purchased natural gas, and
- An increase of $8 million in bad debt expense, primarily resulting from amounts that were previously deferred and began to be recovered as part of SCG's rate increase effective January 1, 2006.

The $225 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $209 million for purchased gas costs, resulting from an increase of $241 million due to higher prices offset by $32 million for lower volumes, and
- An increase of $15 million in other operating and maintenance costs, including $12 million related to an increase in the allowance for doubtful accounts.

Energy East Corporation

Operating Results for the Energy Marketing Business

The primary business included in our Other segment is our energy marketing business comprised of Energetix, Inc. and NYSEG Solutions, Inc., which market electricity and natural gas to customers throughout the state of New York. They currently have 132,000 electricity customers and 42,000 natural gas customers in the service territories of RG&E, NYSEG and several other New York state utilities. Sales and revenues for these companies have become more significant in recent years as changes in the regulatory environment in New York have fostered the development of competitive energy suppliers.

	2006	2005	2004
(Thousands)			
Electricity sales (MWh)	4,516	5,025	4,541
Natural gas sales (Dth)	7,309	10,605	11,194
Operating Revenues			
Electric	$316,221	$409,473	$272,268
Natural gas	81,239	109,608	91,478
Total Operating Revenues	397,460	519,081	363,746
Operating Expenses			
Electricity purchased	300,053	397,251	261,512

Natural gas purchased	75,489	101,073	82,767
Other operating expenses	12,598	13,560	11,419
Total Operating Expenses	388,140	511,884	355,698
Operating Income	$9,320	$7,197	$8,048

Operating Revenues

: The $122 million decrease in operating revenues for 2006 was primarily the result of:

- A decrease of $41 million due to decreased sales volume for electricity due warmer winter weather and cooler summer weather.
- A decrease of $34 million due to decreased sales volume for natural gas due to a significant reduction in heating degree days, and
- A decrease of $52 million due to lower prices for electricity.

Those decreases were partially offset by an increase of $6 million for higher prices for natural gas.

The $155 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $29 million due to increased sales volume for electricity due to customers being added as a result of NYSEG's and RG&E's Voice Your Choice programs.
- An increase of $108 million due to higher prices for electricity, and
- An increase of $23 million due to higher prices for natural gas.

Those increases were offset by a decrease of $5 million due to decreased sales volume for natural gas.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Energy East Corporation

Operating Expenses

: The $124 million decrease in operating expense for 2006 was primarily the result of:

- A decrease of $40 million in purchased electricity due to decreased sales volume,
- A decrease of $31 million in purchased natural gas due to decreased sales volume, and
- A decrease of $57 million in purchased electricity due to lower prices.

Those decreases were partially offset by an increase of $6 million in purchased natural gas due to higher prices.

The $156 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $29 million in purchased electricity due to increased sales volume,
- An increase of $108 million in purchased electricity due to higher prices, and
- An increase of $23 million in purchased natural gas due to higher prices.

Those increases were partially offset by a decrease of $4 million in purchased natural gas due to decreased sales volume.

Other Items

	2006	2005	2004
(Thousands)			
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
Income Taxes on Continuing Operations	$155,255	$169,997	$251,445

Other (Income) and Other Deductions

: (See Item 8 - Note 1 to our Consolidated Financial Statements.)

The changes for 2006 include:

- An $8 million increase in Other (income) from environmental insurance settlements,
- A $4 million increase in Other (income) from higher gains on risk management activity,
- An $11 million increase in Other deductions for the recognition of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and the associated trust preferred securities in July 2006, and
- A $6 million increase in Other deductions from higher losses on risk management contracts.

The changes for 2005 include:

- A $3 million increase in Other (income) from interest income,
- A $6 million decrease in Other (income) due to the effect of a one-time increase as a result of the RG&E Electric Rate Agreement in 2004,
- A $6 million decrease in Other deductions for lower losses on hedge activity related to risk management contracts,
- A $3 million decrease in Other deductions for losses from the disposition of nonutility property, and
- A $4 million increase in Other deductions from miscellaneous losses.

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			
	$4,720,638	$4,753,105	$4,330,472
Utility			
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	Common Stock Outstanding $.01 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Treasury Stock	Total
Balance, January 1, 2004	146,262	$1,463	$1,456,220	$1,126,457	$(11,214)	$(2,820)	$(364)	$2,569,742
Net income				229,337				229,337
Other comprehensive income, net of tax					(32,347)			(32,347)
Comprehensive income								196,990
Common stock dividends declared ($1.055 per share)				(154,261)				(154,261)
Common stock issued - Investor Services Program	872	9	20,962					20,971
	(250)						(6,071)	(6,071)

Common stock repurchased								
Common stock issued - restricted stock plan	242		(132)			(5,784)	5,916	-
Amortization of deferred compensation under restricted stock plan						3,584		3,584
Treasury stock transactions, net	(8)		94				(164)	(70)
Amortization of capital stock issue expense, net			374					374
Balance, December 31, 2004	147,118	1,472	1,477,518	1,201,533	(43,561)	(5,020)	(683)	2,631,259
Net income				256,833				256,833
Other comprehensive income, net of tax					132,646			132,646
Comprehensive income								389,479
Common stock dividends declared ($1.115 per share)				(163,786)				(163,786)
Common stock issued - Investor Services Program	607	6	16,066					16,072
Common stock repurchased	(250)						(6,492)	(6,492)
Common stock issued - restricted stock plan	265		(6,404)			(451)	6,855	-
Amortization of deferred compensation under restricted stock plan						5,471		5,471
Treasury stock transactions, net	(39)		1,702				(1,405)	297
Amortization of capital stock issue			374					374

expense, net								
Balance, December 31, 2005	147,701	1,478	1,489,256	1,294,580	89,085	-	(1,725)	2,872,674
Net income				259,832				259,832
Other comprehensive income, net of tax					(113,502)			(113,502)
Comprehensive income								146,330
Adjustment to initially apply Statement 158					638			638
Common stock dividends declared ($1.17 per share)				(171,951)				(171,951)
Common stock issued - Investor Services Program	204	2	4,943					4,945
Common stock repurchased	(250)						(6,107)	(6,107)
Common stock issued - restricted stock plan	274		(6,722)				6,722	-
Amortization of restricted stock plan grants			8,458					8,458
Treasury stock transactions, net	(22)		(2)				(500)	(502)
Amortization of capital stock issue expense, net			9,862					9,862
Balance, December 31, 2006	147,907	$1,480	$1,505,795	$1,382,461	$(23,779)	-	$(1,610)	$2,864,347

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.

-

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.

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,	2006	2005	2004
(Thousands)			
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:

	2006	2005
(Thousands)		
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:

	Before	After

	Application of Statement 158	Adjustments	Application of Statement 158
(Thousands)			
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.

-

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.

-

Notes to Consolidated Financial Statements

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.)

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)
	66,111	29,406
Other		

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.

-

Notes to Consolidated Financial Statements

Energy East Corporation

Other long-term debt:

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

Amount

Company		Interest Rates	Maturity	(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.

-

Notes to Consolidated Financial Statements

Energy East Corporation

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.

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)	Balance December 31, 2006
(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	$1,382
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)	(16,817)
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,		8,964		167,352		(174,459)	

$(107,041) for 2005 and $112,687 for 2006							
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)	(8,344)
Accumulated Other Comprehensive Income (Loss)	$(11,214)	$(32,347)	$(43,561)	$132,646	$89,085	$(112,864)	$(23,779)

[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)

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

	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		Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	5.75%	5.50%	5.75%	5.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

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		Pension Benefits			Postretirement Benefits	
years ended December 31,	2006	2005	2004	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%

-

Notes to Consolidated Financial Statements

Energy East Corporation

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.

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
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.

Other Market Risk

: 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

Common Stock Outstanding $5 Par Value	Capital in Excess of	Retained	Accumulated Other Comprehensive	Treasury

(Thousands)	Shares	Amount	Par Value	Earnings	Loss	Stock	Total
Balance, January 1, 2004	38,886	$194,429	$556,190	$121,032	-	$(117,238)	$754,413
Net income				70,317			70,317
Other comprehensive income, net of tax					$(26)		(26)
Comprehensive income							70,291
Liquidating dividend			(75,000)				(75,000)
Equity contribution from parent			563				563
Dividends declared							
Preferred stock				(1,789)			(1,789)
Common stock				(170,000)			(170,000)
Balance, December 31, 2004	38,886	194,429	481,753	19,560	(26)	(117,238)	578,478
Net income				78,989			78,989
Other comprehensive income, net of tax					(6,461)		(6,461)
Comprehensive income							72,528
Equity contribution from parent			1,499				1,499
Common stock dividends declared				(70,000)			(70,000)
Balance, December 31, 2005	38,886	194,429	483,252	28,549	(6,487)	(117,238)	582,505
Net income				82,295			82,295
Other comprehensive income, net of tax					1,885		1,885
Comprehensive income							84,180
Adjustment to initially apply Statement 158 for nonqualified plans					(4,505)		(4,505)
Equity contribution from parent			410				410
Common stock dividends declared				(60,000)			(60,000)
Balance, December 31, 2006	38,886	$194,429	$483,662	$50,844	$(9,107)	$(117,238)	$602,590

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.

-

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:

(Thousands)	Before Application of Statement 158	Adjustments	After Application of Statement 158
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

Notes to Financial Statements

Rochester Gas and Electric Corporation

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.

<u>Notes to Financial Statements</u>

Rochester Gas and Electric Corporation

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)
	5,683	7,291
Other		
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.

Notes to Financial Statements

Rochester Gas and Electric Corporation

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.

Rochester Gas and Electric Corporation

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 final billing adjustments.

Note 9. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in RG&E's operations and facilities and may increase the cost of electric and natural gas service.

The EPA and various state environmental agencies have notified RG&E that it is among the potentially responsible parties who may be liable for costs incurred to remediate certain hazardous substances at seven waste sites. The seven sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the seven sites, five sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and three of the sites are also included on the National Priorities List.

Any liability may be joint and several for certain of those sites. RG&E has recorded an estimated liability of less than \$1 million related to the seven sites. It has recorded an estimated liability of \$1 million related to another seven sites where RG&E believes it is probable that it will incur remediation costs, although it has not been notified that it is 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 RG&E.

RG&E has a program to investigate and perform necessary remediation at its 10 sites where gas was manufactured in the past. Eight sites are included in the New York Voluntary Clean-up Program.

RG&E's estimate for all costs related to investigation and remediation of the 10 sites ranges from \$36 million to \$72 million at December 31, 2006. The 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.

RG&E's liability to investigate and perform remediation, as necessary, at its known inactive gas manufacturing sites was \$36 million at December 31, 2006, and \$35 million at December 31, 2005.

RG&E's environmental liability accruals, which are expected to be paid within the next 12 years, have been established on an undiscounted basis. RG&E has received insurance settlements during the last three years, which it accounted for as reductions in its related regulatory asset.

Rochester Gas and Electric Corporation

Note 10. Fair Value of Financial Instruments

The carrying amounts and estimated fair values of RG&E's 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	$11,120	$11,120	$11,374	$11,374
First mortgage bonds	$570,625	$588,545	$570,551	$629,990
Pollution control notes, fixed	$25,500	$26,737	$25,500	$27,745
Pollution control notes, variable	$101,900	$101,900	$101,900	$101,900

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

-

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 11. Accumulated Other Comprehensive Loss

	Balance January 1, 2005	2005 Change	Balance December 31, 2005	2006 Change	Balance December 31, 2006
(Thousands)					
Unrealized (losses) gains on investments:					
Unrealized holding (losses) gains during period, net of income tax benefit (expense) of $19 for 2005, and $(385) for 2006		$(29)		$581	
Net unrealized (losses) gains on investments		(29)	$(29)	581	$552
Minimum pension liability adjustment, net of income tax benefit (expense) of $2,538 for 2005 and $(2,538) for 2006		(3,827)	(3,827)	3,827	-

Adjustment to initially apply Statement 158 for nonqualified plans, net of income tax benefit of $2,987 for 2006				(4,505)	(4,505)
Unrealized (losses) gains on derivatives qualified as hedges:					
Unrealized (losses) gains during period on derivatives qualified as hedges, net of income tax benefit (expense) of $150 for 2005, and $6,223 for 2006		(200)		(9,383)	
Reclassification adjustment for (gains) included in net income, net of income tax expense of $1,595 for 2005 and $(4,549) for 2006		(2,405)		6,860	
Net unrealized (losses) on derivatives qualified as hedges	$(26)	(2,605)	(2,631)	(2,523)	(5,154)
Accumulated Other Comprehensive Loss	$(26)	$(6,461)	$(6,487)	$(2,620)	$(9,107)

(See Risk management in Note 1.)

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 12. Retirement Benefits

RG&E has funded noncontributory defined benefit pension plans that cover substantially all of its employees. The plans provide defined benefits based on years of service and final average salary. RG&E also has other postretirement health care benefit plans covering substantially all of its 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	$509,085	$515,669	$82,772	$102,411
Service cost	4,701	4,862	636	731
Interest cost	26,841	31,323	4,453	5,519
Actuarial loss (gain)	(18,774)	11,945	(2,537)	(15,304)
Benefits paid	(40,583)	(37,088)	(5,200)	(5,286)
Federal subsidiary on benefits paid	-	-	212	-
Other	-	(17,626)	-	(5,299)
Benefit obligation at December 31	$481,270	$509,085	$80,336	$82,772
Change in plan assets				
Fair value of plan assets at January 1	$542,355	$575,967	-	-
Actual return on plan assets	76,677	38,362	-	-
Employer contributions	-	-	$5,200	$5,286
Benefits paid	(40,582)	(37,088)	(5,200)	(5,286)
Other	-	(34,886)	-	-
Fair value of plan assets at December 31	$578,450	$542,355	-	-
Funded status at December 31	$97,180	$33,270	$(80,336)	$(82,772)
Unrecognized net actuarial loss (gain) (1)		$831		$(13,289)
Unrecognized prior service cost (1)		14,267		5,052
Unrecognized net transition obligation (1)		-		10,964
Total unrecognized amounts		$15,098		$2,727
Prepaid (accrued) benefit cost		$48,368		$(80,045)

(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	$97,180		-	
Current liabilities	-		$(5,753)	
Noncurrent liabilities	-		(74,583)	
	$97,180		$(80,336)	

-

Notes to Financial Statements

Rochester Gas and Electric Corporation

Amounts recognized in regulatory assets or regulatory liabilities at December 31, 2006, consist of:

	Pension Benefits	Postretirement Benefits
(Thousands)		
Net loss (gain)	$(46,303)	$(14,505)
Prior service cost	$12,784	$4,193
Transition obligation	-	$9,137

RG&E's accumulated benefit obligation for all defined benefit pension plans at December 31 was $438 million for 2006 and $459 million for 2005.

RG&E's postretirement benefits were unfunded at December 31, 2006 and 2005.

	Pension Benefits			Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
(Thousands)						
Components of net periodic benefit cost						
Service cost	$4,701	$4,862	$5,479	$636	$731	$1,030
Interest cost	26,841	31,323	29,805	4,453	5,519	6,054
Expected return on plan assets	(45,942)	(45,148)	(49,184)	-	-	-
Amortization of transition obligation	-	-	-	1,828	1,828	2,119
Amortization of prior service cost	1,483	1,483	1,262	859	859	1,141
Amortization of net (gain)	(2,376)	(2,991)	(6,906)	(1,322)	(3)	(263)
Curtailment	-	-	(11,835)	-	-	7,401
Settlement charge	-	-	10,007	-	-	(7,007)
Net periodic benefit cost	$(15,293)	$(10,471)	$(21,372)	$6,454	$8,934	$10,475

RG&E includes 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. RG&E expects to recover any costs related to the transition obligation by 2011. RG&E is 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 and regulatory liabilities into net periodic benefit cost for the fiscal year ended December 31, 2007	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net (gain)	$(4,033)	$(1,628)
Estimated prior service cost	$1,483	$859

Estimated transition obligation	-	$1,827

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

-

Notes to Financial Statements

Rochester Gas and Electric Corporation

As of December 31, 2006, RG&E increased its discount rate from 5.50% to 5.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. RG&E 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 its benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for	Pension Benefits			Postretirement Benefits		
years ended December 31,	2006	2005	2004	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%	N/A	N/A	N/A
Rate of compensation increase	4.00%	4.00%	4.00%	N/A	N/A	N/A

RG&E developed its 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, RG&E selected an assumption of 8.75% per year, which is lower than the rate that would otherwise be determined solely based on historical returns. RG&E amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred.

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	-	$(3)
Effect on postretirement benefit obligation	$7	$(74)

Plan assets

: RG&E's pension plan weighted-average asset allocations at December 31, 2006 and 2005, by asset category, are:

Asset Category	Target Allocation	2006	2005
Equity securities	58%	64%	64%
Debt securities	27%	24%	28%
Real estate	5%	4%	2%
Other	10%	8%	6%
Total	100%	100%	100%

Notes to Financial Statements

Rochester Gas and Electric Corporation

RG&E's pension plan assets are held in a master trust with a trustee and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with RG&E's risk tolerance. This is achieved 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.

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

Contributions

: RG&E does not anticipate any contributions to its pension benefit plans in 2007.

Estimated future benefit payments

: RG&E's 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	$35,134	$9,009	$230
2008	$35,775	$9,367	$237
2009	$36,563	$9,725	$242
2010	$38,747	$10,135	$241
2011	$42,260	$10,329	$227
2012 - 2016	$238,173	$53,159	$1,057

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 13. Segment Information

Selected financial information for RG&E's operating segments is presented in the table below. RG&E's electric delivery segment consists of its regulated transmission, distribution and generation operations. Its natural gas delivery segment consists of its regulated transportation, storage and distribution operations. RG&E measures segment profitability based on net income.

	Electric Delivery	Natural Gas Delivery	Total
(Thousands)			
2006			
Operating Revenues	$731,185	$385,108	$1,116,293
Depreciation and Amortization	$52,617	$18,668	$71,285
Interest Charges, Net	$43,393	$12,810	$56,203
Income Taxes	$41,518	$11,242	$52,760
Net Income	$59,881	$22,414	$82,295
Total Assets	$1,785,881	$694,509	$2,480,390
Capital Spending	$101,543	$39,489	$141,032
2005			
Operating Revenues	$691,159	$414,367	$1,105,526
Depreciation and Amortization	$53,607	$19,251	$72,858
Interest Charges, Net	$43,890	$12,555	$56,445
Income Taxes	$22,144	$12,518	$34,662
Net Income	$61,106	$17,883	$78,989
Total Assets	$1,715,237	$667,036	$2,382,273
Capital Spending	$39,924	$15,526	$55,450
2004			
Operating Revenues	$664,794	$369,263	$1,034,057
Depreciation and Amortization	$71,080	$18,742	$89,822
Interest Charges, Net	$41,914	$12,917	$54,831
Income Taxes	$145,697	$7,630	$153,327
Net Income	$51,095	$19,222	$70,317
Total Assets	$1,670,657	$649,700	$2,320,357
Capital Spending	$58,836	$22,881	$81,717

Note 14. Quarterly Financial Information (Unaudited)

Quarter Ended	March 31	June 30	September 30	December 31
(Thousands)				
2006				
Operating Revenues	$346,511	$236,108	$252,487	$281,187
Operating Income	$77,168	$33,139	$34,947	$42,854
Net Income and Earnings Available for Common Stock	$40,285	$11,952	$12,441	$17,617
2005				

Operating Revenues	$315,720	$225,817	$259,439	$304,550
Operating Income	$64,878	$32,735	$34,303	$36,473
Net Income and Earnings Available for Common Stock	$30,928	$10,976	$15,512	$21,573

Report of Independent Registered Public Accounting Firm

To the Shareholder and Board of Directors of
Rochester Gas and Electric Corporation:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation at December 31, 2006 and 2005, and the results of its operations and its 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 financial statements. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the 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).*

PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 28, 2007

ROCHESTER GAS AND ELECTRIC CORPORATION

SCHEDULE II - 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	$13,482	$10,814	$(10,814)	$(2,582)	$10,900
2005					
Allowance for Doubtful Accounts - Accounts Receivable	$21,482	$3,902	$(3,902)	$(8,000)	$13,482
2004					
Allowance for Doubtful Accounts - Accounts Receivable	$27,182	$4,733	$(4,733)	$(5,700)	$21,482

(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.

PART

III

Energy East

: Information required by Part III as to Energy East is incorporated herein by reference to the information under the caption(s), indicated in the table below, in Energy East's Proxy Statement, which will be filed with the Commission on or before April 30, 2007.

	Caption(s) in Energy East's Proxy Statement
Item 10. Directors and Executive Officers and Corporate Governance of the Registrants	"Corporate Governance, " "Committees, " "Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance"
Item 11. Executive Compensation	"Compensation Discussion and Analysis, " "Compensation Committee Report, " "Summary Compensation Table, " "Grants of Plan-Based Awards, " "Outstanding Equity Awards at Fiscal Year End," "Option Exercises and Stock Vested, " "Pension Benefits, " "Summary of Potential Post Employment Termination Payments, " "Directors' Compensation, "
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	"Security Ownership of Certain Beneficial Owners and Management"

Item 13. Certain Relationships and Related Transactions, and Director Independence	"Election of Directors," "Related Party Transactions Policy"
Item 14. Principal Accounting Fees and Services	"Independent Accountants, " "Audit Fees, " "Audit-Related Fees, " "Tax Fees" and "All Other Fees"

Information for Item 10 regarding executive officers of Energy East is on page

I-17 of this report.

RG&E

: RG&E meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, the information required for Items 10, 11, 12 and 13 in this Part III related to RG&E is not presented.

Item 14. Principal Accounting Fees and Services

Audit Fees

: Aggregate fees billed to or allocated to RG&E by Energy East as part of its consolidated audits for each of the last two fiscal years for professional services rendered for the audit of RG&E's annual financial statements and the reviews of the financial statements included in RG&E's Forms 10-Q were $1,180,467 for 2006 and $667,233 for 2005.

Audit-Related Fees

: Aggregate fees billed to or allocated to RG&E by Energy East for each of the last two fiscal years for assurance and related services reasonably related to the performance of the audit of RG&E's annual financial statements and the reviews of the financial statements included in RG&E's Forms 10-Q were $- for 2006 and $2,389 for 2005, consisting of the following:

	2006	2005
Benefit Plan Audits	-	$1,389
Agreed Upon Procedures Letters	$1,000	$1,000

Tax Fees

: Aggregate fees billed to or allocated to RG&E by Energy East for each of the last two fiscal years for professional tax services rendered consisting of tax compliance and refunds were $8,015 for 2006 and $10,406 for 2005.

All Other Fees

: Other fees were $275 for 2006 and $1,500 for 2005.

PART IV

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as part of this report for Energy East:

Financial statements

Included in Part II of this report:

Consolidated Balance Sheets as of December 31, 2006 and 2005
For the three years ended December 31, 2006
Consolidated Statements of Income
Consolidated Statements of Cash Flows
Consolidated Statements of Changes in Common Stock Equity
Notes to Consolidated Financial Statements
Report of Independent Registered Public Accounting Firm

Financial statement schedule

Included in Part II of this report:
For the three years ended December 31, 2006
II. Consolidated Valuation and Qualifying Accounts

The following documents are filed as part of this report for RG&E:

Financial statements

Included in Part II of this report:

Balance Sheets as of December 31, 2006 and 2005
For the three years ended December 31, 2006
Statements of Income
Statements of Cash Flows
Statements of Changes in Common Stock Equity
Notes to Financial Statements
Report of Independent Registered Public Accounting Firm

Financial statement schedule

Included in Part II of this report:
For the three years ended December 31, 2006
II. Valuation and Qualifying Accounts

Schedules other than those listed above have been omitted since they are not required, are inapplicable or the required information is presented in the Consolidated Financial Statements, Financial Statements or notes thereto.

Exhibits

(a)(1) The following exhibits are delivered with this report:

Registrant	Exhibit No.	Description
Energy East Corporation	(A)10-17 -	Amended and Restated Employment Agreement dated as of December 31, 2006, by and among the Company, Energy East Management Corporation and W. W. von Schack.
	(A)10-26 -	Award Agreement (February 2007) under the 2000 Stock Option Plan.
	12-1 -	Computation of Ratio of Earnings to Fixed Charges.
	12-2 -	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
	21 -	Subsidiaries.
	23 -	Consent of PricewaterhouseCoopers LLP to incorporation by reference into certain registration statements.
	31-1 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
	31-2 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
	*32 -	Certifications under Section 906 of the Sarbanes-Oxley Act of 2002.
Rochester Gas and Electric Corporation	31-1 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
	31-2 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
	*32 -	Certifications under Section 906 of the Sarbanes-Oxley Act of 2002.

* Furnished pursuant to Regulation S-K Item 601(b)(32).

(A) Management contract or compensatory plan or arrangement.

(a)(2) The following exhibits are incorporated herein by reference:

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New	

	York on April 23, 1998 - Post-effective Amendment No.1 to Registration No. 033-54155	4-1
3-2 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on April 26, 1999 - Company's 10-Q for the quarter ended March 31, 1999 - File No. 1-14766	3-3
3-3 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 21, 2004 - Company's 10-Q for the quarter ended June 30, 2004 - File No. 1-14766	3-5
3-4 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 12, 2006 - Company's 10-Q for the quarter ended June 30, 2006 - File No. 1-14766.	3-6
3-5 -	By-laws of the Company as amended April 6, 2006 - Company's 10-Q for the quarter ended March 31, 2006 - File No. 1-14766	3-4
4-1 -	Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	4-1
4-2 -	Third Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of November 14, 2000 related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-K for the year ended December 31, 2000 - File No. 1-14766	4-3
4-3 -	Fourth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of November 14, 2001, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-K for the year ended December 31, 2001 - File No. 1-14766	4-4

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	4-4 -	Sixth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of June 14, 2002, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended June 30, 2002 - File No. 1-14766	4-6
	4-5 -	Seventh Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of September 9, 2003, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended September 30, 2003 - File No. 1-14766	4-9
	4-6 -	Eighth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2006, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended September 30, 2006 - File No. 1-14766	4-8
	(A)10-1 -	Deferred Compensation Plan for Directors - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-40
	(A)10-2 -	Amended and Restated Director Share Plan - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-38
	(A)10-3 -	Amendment No. 1 to Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-3
	(A)10-4 -	Amendment No. 2 to Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-4
	(A)10-5 -	Deferred Compensation Plan - Director Share Plan - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-39
	(A)10-6 -	Amendment No. 1 to Deferred Compensation Plan - Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-6
	(A)10-7 -		

		Supplemental Executive Retirement Plan - Company's 10-Q for the quarter ended September 30, 2001 - File No. 1-14766	10-33
	(A)10-8 -	Supplemental Executive Retirement Plan Amendment No. 1 - Company's 10-K for the year ended December 31, 2001 - File No. 1-14766	10-5

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	(A)10-9 -	Supplemental Executive Retirement Plan Amendment No. 2 - Company's 10-Q for the quarter ended June 30, 2004 - File No. 1-14766	10-22
	(A)10-10 -	Supplemental Executive Retirement Plan Amendment No. 3 - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-10
	(A)10-11 -	Annual Executive Incentive Plan - Company's 10-K for the year ended December 31, 2000 - File No. 1-14766	10-8
	(A)10-12 -	Annual Executive Incentive Plan Amendment No. 1 Company's 10-K for the year ended December 31, 2000 - File No. 1-14766	10-9
	(A)10-13 -	Annual Executive Incentive Plan Amendment No. 2 - Company's 10-Q for the quarter ended June 30, 2001 - File No. 1-14766	10-28
	(A)10-14 -	Annual Executive Incentive Plan Amendment No. 3 - Company's 10-Q for the quarter ended March 31, 2005 - File No. 1-14766	10-22
	(A)10-15 -	Deferred Compensation Plan, effective January 1, 2004 - Company's 10-K for the year ended December 31, 2003 - File No. 1-14766	10-9
	(A)10-16 -	Amendment No. 1 to Deferred Compensation Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-16
	(A)10-18 -	Amended and Restated Employment Agreement dated as of June 14, 1999, by and among the Company, CMP Group, Inc. and F. Michael McClain, Jr. - Company's 10-Q for the quarter ended June 30, 2005 - File No.1-14766	10-24
	(A)10-19 -		

		Restricted Stock Plan - Company's 10-K for the year ended December 31, 1998 - File No. 1-14766	10-36
	(A)10-20 -	Restricted Stock Plan Amendment No. 1 - Company's 10-K for the year ended December 31, 2002 - File No. 1-14766	10-16
	(A)10-21 -	Form of Restricted Stock Award Grant - Company's 10-Q for the quarter ended March 31, 2005 - File No. 1-14766	10-23
	(A)10-22 -	Amended and Restated 2000 Stock Option Plan, effective October 15, 2003 - Company's 10-Q for the quarter ended September 30, 2003 - File No. 1-14766	10-27
	(A)10-23 -	Award Agreement under the 2000 Stock Option Plan - Company's 10-Q for the quarter ended June 30, 2000 - File No. 1-14766	10-37
	(A)10-24 -	Award Agreement (February 2001) under the 2000 Stock Option Plan - Company's 10-K for the year ended December 31, 2000 - File No. 1-14766	10-27

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	(A)10-25 -	Award Agreement (February 2006) under the 2000 Stock Option Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-26
	(A)10-27 -	Amended and Restated Director's Charitable Giving Program - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-27
	(A)10-28 -	Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement - Company's 10-K for the year ended December 31, 2001 - File No. 1-14766	10-24
	(A)10-29 -	Energy East Management Corporation Form of Severance Agreement for executive officers who do not have	

		employment agreements - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-29
	(A)10-30 -	ERISA Excess Plan effective January 1, 2005- Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-30
Rochester Gas and Electric Corporation	3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New York on June 23, 1992 - Registration No. 33-49805	4-5
	3-2 -	Certificate of Amendment of the Certificate of Incorporation of the Company under Section 805 of the Business Corporation Law filed with the Secretary of State of the state of New York on March 18, 1994 - Company's 10-Q for the quarter ended March 31, 1994 - File No. 1-672	4
	3-3 -	By-Laws of Company as amended June 28, 2002 - Company's 10-Q for the quarter ended June 30, 2002 - File No. 1-672	3-3
	4-1 -	General Mortgage to Bankers Trust Company, as Trustee, dated September 1, 1918, and supplements thereto, dated March 1, 1921, October 23, 1928, August 1, 1932 and May 1, 1940 - Company's 10-K for the year ended December 31, 1990 - File No. 1-672	4-2
	4-2 -	Supplemental Indenture, dated as of March 1, 1983, between the Company and Bankers Trust Company, as Trustee - Company's 8-K dated July 15, 1993 - File No. 1-672	4-1
	10-1 -	Agreement dated February 5, 1980 between the Company and the Power Authority of the state of New York - Company's 10-K for the year ended December 31, 1989 - File No. 1-672	10-10

Registrant	Exhibit No.	Filed in	As Exhibit No.
Rochester Gas and Electric Corporation	10-2 -	Agreement dated March 9, 1990 between the Company and Mellon Bank, N.A. - Company's 10-Q for the quarter ended March 31, 1990 - File No. 1-672	10-1

10-3 -	Agreement between New York Independent System Operator and Transmission Owners, dated as of December 2, 1999 - New York State Electric & Gas Corporation's 10-K for the year ended December 31, 1999 - File No. 1-3103-2	10-1
10-4 -	Independent System Operator Agreement, dated as of December 2, 1999 - New York State Electric & Gas Corporation's 10-K for the year ended December 31, 1999 - File No. 1-3103-2	10-2
10-5 -	Asset Purchase Agreement by and among Rochester Gas and Electric Corporation, Constellation Generation Group, LLC and Constellation Energy Group, Inc. dated as of November 24, 2003 - Company's 10-K for the year ended December 31, 2003 - File No. 1-672	10-7
10-6 -	Power Purchase Agreement between Constellation Power Source, Inc. and the Company dated as of November 24, 2003 - Company's 10-Q for the quarter ended September 30, 2005 - File No. 1-672	10-28

(A) Management contract or compensatory plan or arrangement.

Energy East agrees to furnish to the Commission, upon request, a copy of the following documents:

A. Five-Year Revolving Credit Agreement among Energy East, certain lenders, Citibank, N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent and HSBC Bank USA, National Association, UBS Securities LLC and Wachovia Bank, N.A., as Co-Documentation Agents, as amended and restated as of June 2, 2006.

B. Five-Year Revolving Credit Agreement among RG&E, New York State Electric & Gas Corporation, Central Maine Power Company, The Southern Connecticut Gas Company, Connecticut Natural Gas Corporation and The Berkshire Gas Company, certain lenders, Wachovia Bank N.A., as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent and The Bank of New York, Citibank, N.A. and Sovereign Bank, as Co-Documentation Agents, as amended and restated as of June 2, 2006 (the "Joint Revolving Credit Agreement").

C. Indenture dated as of August 1, 1989, between Central Maine Power Company and The Bank of New York, and the Supplemental Indentures related thereto.

D. Loan and Trust Agreement dated as of December 1, 2001, among the Business Finance Authority of the state of New Hampshire, Central Maine Power Company and State Street Bank and Trust company, as Trustee, relating to Pollution Control Revenue Refunding Bonds (Series 2001).

E. The Southern Connecticut Gas Company's Indenture, dated as of March 1, 1948, with The Bridgeport City Trust Company (now US Bank, N.A.), as Trustee, and Supplemental Indentures related thereto.

F. Connecticut Natural Gas Corporation's Issuing and Paying Agency Agreement with The Connecticut National Bank (now US Bank, N.A.) for Medium Term Notes, Series A, dated

November 1, 1991.

G. Connecticut Natural Gas Corporation's Issuing and Paying Agency Agreement with Shawmut Bank Connecticut, National Association (now US Bank, N.A.) for Medium Term Notes, Series B, dated June 14, 1994, and an Amendment related thereto.

H. Connecticut Natural Gas Corporation's Issuing and Paying Agency Agreement with US Bank, N.A. for Medium Term Notes, Series C, dated September 12, 2005.

I. The Berkshire Gas Company's First Mortgage Indenture and Deed of Trust, dated as of July 1, 1954, with Chemical Corn Exchange Bank (now The Bank of New York), and the Supplemental Indenture related thereto.

J. Loan Agreement, dated April 30, 2004, between The Berkshire Gas Company and Banknorth, N.A.

K. Senior Note Agreement dated as of July 1, 1990 between The Berkshire Gas Company and Allstate Life Insurance Company.

L. Senior Note Agreement dated as of November 1, 1996 between The Berkshire Gas Company and First Colony Life Insurance Company, and Amendments related thereto.

The total amount of securities authorized under each of such documents does not exceed 10% of the total assets of Energy East.

RG&E agrees to furnish to the Commission, upon request, a copy of the Participation Agreement dated as of August 1, 1997, between RG&E and NYSERDA relating to Pollution Control Revenue Bonds, Rochester Gas and Electric Corporation Project (1997 Series A), (1997 Series B), (1997 Series C) and (1998 Series A); a copy of the Participation Agreements dated as of August 1, 2004, between RG&E and NYSERDA relating to Pollution Control Revenue Bonds (2004 Series A) and (2004 Series B); a copy of certain supplemental indentures to the General Mortgage dated September 1, 1918, as supplemented; and a copy of the Joint Revolving Credit Agreement. The total amount of securities authorized under each of such documents does not exceed 10% of the total assets of RG&E.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY EAST CORPORATION

Date: February 28, 2007

By /s/Robert D. Kump
Robert D. Kump
Senior Vice President &
Chief Financial Officer

ROCHESTER GAS AND ELECTRIC CORPORATION

Date: February 28, 2007

By /s/Joseph J. Syta
Joseph J. Syta
Vice President - Controller and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of each Registrant and in the capacities and on the dates indicated.

ENERGY EAST CORPORATION
PRINCIPAL EXECUTIVE OFFICER

Date: February 28, 2007

By /s/Wesley W. von Schack
Wesley W. von Schack
Chairman, President, Chief
Executive Officer & Director

PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER

Date: February 28, 2007

By /s/Robert D. Kump
Robert D. Kump
Senior Vice President &
Chief Financial Officer

Signatures

(Continued)

ENERGY EAST CORPORATION, continued

Date: February 28, 2007

By /s/James H. Brandi
James H. Brandi, Director

Date: February 28, 2007

By /s/John T. Cardis
John T. Cardis, Director

Date: February 28, 2007

By /s/Joseph J. Castiglia
Joseph J. Castiglia, Director

Date: February 28, 2007

By /s/Lois B. DeFleur
Lois B. DeFleur, Director

Date: February 28, 2007

By /s/G. Jean Howard
G. Jean Howard, Director

Date: February 28, 2007

By /s/David M. Jagger
David M. Jagger, Director

Date: February 28, 2007

By /s/Seth A. Kaplan
Seth A. Kaplan, Director

Date: February 28, 2007

By /s/Ben E. Lynch
Ben E. Lynch, Director

Date: February 28, 2007

By /s/Peter J. Moynihan
Peter J. Moynihan, Director

Date: February 28, 2007

By /s/Walter G. Rich
Walter G. Rich, Director

Signatures

(Continued)

ROCHESTER GAS AND ELECTRIC CORPORATION
PRINCIPAL EXECUTIVE OFFICER

Date: February 28, 2007

By /s/James P. Laurito
James P. Laurito
Director, President and Chief Executive Officer

PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER

Date: February 28, 2007

By /s/Joseph J. Syta
Joseph J. Syta
Vice President - Controller and Treasurer

Date: February 28, 2007

By /s/Robert E. Rude
Robert E. Rude, Director

Date: February 28, 2007

By /s/Wesley W. von Schack
Wesley W. von Schack, Director

EXHIBIT INDEX

Registrant	Exhibit No.	Description
Energy East Corporation	*3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New York on April 23, 1998.
	*3-2 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on April 26, 1999.
	*3-3 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 21, 2004.
	*3-4 -	Certificate of Amendment of the Certificate of Incorporation filed in the office of the Secretary of State of the state of New York on June 12, 2006.
	*3-5 -	By-Laws of the Company as amended April 6, 2006.
	*4-1 -	Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of August 31, 2000.
	*4-2 -	Third Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of November 14, 2000 related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
	*4-3 -	Fourth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of November 14, 2001, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
	*4-4 -	Sixth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of June 14, 2002, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
	*4-5 -	Seventh Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of September 9, 2003, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
	*4-6 -	Eighth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2006, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
	*(A)10-1 -	Deferred Compensation Plan for Directors.
	*(A)10-2 -	Amended and Restated Director Share Plan.
	*(A)10-3 -	Amendment No. 1 to Director Share Plan.
	*(A)10-4 -	Amendment No. 2 to Director Share Plan.

*(A)10-5 - Deferred Compensation Plan Director Share Plan.

*(A)10-6 - Amendment No. 1 to Deferred Compensation Plan - Director Share Plan.

*(A)10-7 - Supplemental Executive Retirement Plan.

*(A)10-8 - Supplemental Executive Retirement Plan Amendment No. 1.

*(A)10-9 - Supplemental Executive Retirement Plan Amendment No. 2.

*(A)10-10 - Supplemental Executive Retirement Plan Amendment No. 3.

EXHIBIT INDEX (Continued)

Registrant	Exhibit No.	Description
Energy East Corporation	*(A)10-11 -	Annual Executive Incentive Plan.
	*(A)10-12 -	Annual Executive Incentive Plan Amendment No. 1.
	*(A)10-13 -	Annual Executive Incentive Plan Amendment No. 2.
	*(A)10-14 -	Annual Executive Incentive Plan Amendment No. 3.
	*(A)10-15 -	Deferred Compensation Plan, effective January 1, 2004.
	*(A)10-16 -	Amendment No. 1 to Deferred Compensation Plan.
	(A)10-17 -	Amended and Restated Employment Agreement dated as of December 31, 2006, by and among the Company, Energy East Management Corporation and W. W. von Schack.
	*(A)10-18 -	Amended and Restated Employment Agreement dated as of June 14, 1999, by and among the Company, CMP Group, Inc. and F. Michael McClain, Jr.
	*(A)10-19 -	Restricted Stock Plan.
	*(A)10-20 -	Restricted Stock Plan Amendment No. 1.
	*(A)10-21 -	Form of Restricted Stock Award Grant.
	*(A)10-22 -	Amended and Restated 2000 Stock Option Plan, effective October 15, 2003.
	*(A)10-23 -	Award Agreement under the 2000 Stock Option Plan.
	*(A)10-24 -	Award Agreement (February 2001) under the 2000 Stock Option Plan.
	*(A)10-25 -	Award Agreement (February 2006) under the 2000 Stock Option Plan.
	(A)10-26 -	Award Agreement (February 2007) under the 2000 Stock Option Plan.
	*(A)10-27 -	Amended and Restated Director's Charitable Giving Program.
	*(A)10-28 -	Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement.
	*(A)10-29 -	Energy East Management Corporation Form of Severance Agreement for executive officers who do not

	have employment agreements.
*(A)10-30 -	ERISA Excess Plan effective January 1, 2005.
12-1 -	Computation of Ratio of Earnings to Fixed Charges.
12-2 -	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
21 -	Subsidiaries.
23 -	Consent of PricewaterhouseCoopers LLP to incorporation by reference into certain registration statements.
31-1 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31-2 -	Certification under Section 302 of the Sarbanes-Oxley Act of 2002.
**32 -	Certifications under Section 906 of the Sarbanes-Oxley Act of 2002.

EXHIBIT INDEX (Continued)

Registrant	Exhibit No.	Description
Rochester Gas and Electric Corporation	*3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New York on June 23, 1992.
	*3-2 -	Certificate of Amendment of the Certificate of Incorporation of the Company under Section 805 of the Business Corporation Law filed with the Secretary of State of the state of New York on March 18, 1994.
	*3-3 -	By-Laws of the Company as amended June 28, 2002.
	*4-1 -	General Mortgage to Bankers Trust Company, as Trustee, dated September 1, 1918, and supplements thereto, dated March 1, 1921, October 23, 1928, August 1, 1932 and May 1, 1940.
	*4-2 -	Supplemental Indenture, dated as of March 1, 1983, between the Company and Bankers Trust Company, as Trustee.
	*10-1 -	Agreement dated February 5, 1980 between the Company and the Power Authority of the state of New York.
	*10-2 -	Agreement dated March 9, 1990 between the Company and Mellon Bank, N.A.

*10-3 - Agreement between New York Independent System Operator and Transmission Owners, dated as of December 2, 1999.

*10-4 - Independent System Operator Agreement, dated as of December 2, 1999.

*10-5 - Asset Purchase Agreement by and among Rochester Gas and Electric Corporation, Constellation Generation Group, LLC and Constellation Energy Group, Inc. dated as of November 24, 2003.

*10-6 - Power Purchase Agreement between Constellation Power Source, Inc. and the Company dated as of November 24, 2003.

31-1 - Certification under Section 302 of the Sarbanes-Oxley Act of 2002.

31-2 - Certification under Section 302 of the Sarbanes-Oxley Act of 2002.

**32 - Certifications under Section 906 of the Sarbanes-Oxley Act of 2002.

---

* Incorporated by reference.

** Furnished pursuant to Regulation S-K Item 601(b)(32).

(A) Management contract or compensatory plan or arrangement.