ROCHESTER GAS & ELECTRIC CORP
Form 10-K
March 01, 2006

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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, 2005**

OR

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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 (585) 546-2700	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 non-accelerated 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, 2005, the last business day of Energy East's most recently completed second fiscal quarter, was $4,273,951,157.

As of February 15, 2006, shares of common stock outstanding for each registrant were:

Registrant	Description	Shares
Energy East Corporation	Par value $.01 per share	147,679,538
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 May 1, 2006.	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.

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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 (CNE), CMP Group, CTG Resources, Inc., Berkshire Energy Resources, The Energy Network and Energy East Enterprises.

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 New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (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.

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 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

Constellation Nuclear Constellation Nuclear, LLC is a member of The Constellation Energy Group

DOE United States Department of Energy

DPUC Connecticut Department of Public Utility Control

DSM demand-side management

DTE Massachusetts Department of Telecommunications and Energy

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

Ginna

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

IRP Incentive Rate Plan

ISO New England ISO New England Inc.

ITC investment tax credit

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

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

MPUC Maine Public Utilities Commission

MW megawatt

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 Service Commission

NYPSC February 2002 Order NYPSC order issued in February 2002 approving NYSEG's five-year electric rate plan, which extends through December 31, 2006

NYSDEC New York State Department of

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

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

Environmental Conservation

NYSERDA New York State Energy Research and Development Authority

OCC The Office of Consumer Counsel in the State of Connecticut

PCN pollution control notes

Glossary of Terms (Continued)

Penelec

Pennsylvania Electric Company

PJM Interconnection PJM Interconnection, LLC

Policy Statement NYPSC Statement of Policy on Further Steps Toward Competition in Retail Energy Markets

ROE return on equity

RTO Regional Transmission Organization

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

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 150 Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

VEBA voluntary employees' beneficiary association

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

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

1990 Amendments The Clean Air Act Amendments of 1990

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 increasingly competitive electric and/or natural gas utility markets,
- regulatory uncertainty in a politically-charged environment of escalating and volatile energy prices,
- the impacts of the NYPSC End State model experiment adopted in its Collaborative on End State of Energy Competition,
- enactment and 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,
- the operation of ISO New England as an RTO,
- 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 rapidly increasing commodity costs on customer usage and uncollectible expense,
- our ability to achieve and maintain enterprise-wide integration synergies,
- market risk,
- our ability to obtain adequate and timely rate relief and/or the extension of current rate plans,
- the possible discontinuation 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 in the areas in which we do business,
- extreme weather-related events such as hurricanes, ice storms or snow storms,
- weather variations affecting customer energy usage,
- authoritative accounting guidance,
- acts of terrorism,
- the effect of the 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. Our corporate offices are located in New York and Maine. We became the parent of the following companies as indicated: New York State Electric & Gas Corporation in May 1998; CNE in February 2000; CMP Group, CTG Resources and Berkshire Energy in September 2000; and RGS Energy in June 2002.

CNE, CMP Group, CTG Resources, Berkshire Energy and RGS Energy are wholly-owned Energy East subsidiaries.

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. CMP sold their generation assets in 2000.

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 Rochester Gas and Electric Corporation. 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 the remaining assets in 2002. 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, and plans to shut down its largest remaining generating facility, Russell Station, in 2007 upon the completion of a transmission upgrade required to assure reliable delivery. See Item 7 - MD&A - RG&E Transmission Project.

Energy East created a support services company in 2004, Utility Shared Services Corporation, to consolidate support service functions for its 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 a wholly-owned subsidiary and also became the holding company for NYSEG.

The following general developments have occurred in our businesses since January 1, 2005:

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. With the passage of the Energy Policy Act of 2005, which repealed PUHCA, the FERC and state utility commissions have new authority to regulate and monitor, among other things, intercompany cost allocations of holding company systems such as Energy East.

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

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

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

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 56% in 2005, 58% in 2004 and 61% in 2003. Operating revenues from regulated natural gas sales were 34% in 2005, 33% in 2004 and 32% in 2003. 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 860,000 electricity and 254,000 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 63% of RG&E's operating revenues for 2005, 64% for 2004 and 66% for 2003 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 589,000 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 and Bath-Brunswick areas.

SCG

conducts natural gas transportation and distribution operations in Connecticut serving approximately 175,000 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.

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 10% of Energy East's total revenues in 2005, 9% in 2004 and 7% in 2003.

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

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

includes Maine Natural Gas, a small natural gas delivery company; New Hampshire Gas, a propane air delivery company; and Seneca Lake Storage, which owns development rights for a potential high-deliverability natural gas storage facility in upstate New York.

Energy East Telecommunications

owns fiber optic lines in central New York that it leases to retail communications companies. 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.

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 2005 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 2005 through purchases under long-term contracts with the New York Power Authority, Constellation Nuclear and CGG. A small portion (less than 20%) of its power requirements for 2005 were 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.

Nuclear -

RG&E sold Ginna to CGG in June 2004, but retains a power entitlement to 90% of Ginna's output under a 10-year contract with CGG. (See Item 8 - Note 2 to our Consolidated Financial Statements and Note 2 to RG&E's Financial Statements.)

Coal

- RG&E's 2006 coal requirements are expected to be approximately 500,000 tons. RG&E's coal supply portfolio contains both spot and term agreements with multiple suppliers. In 2005, 95% of RG&E's coal requirements were purchased under contract and 5% were 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 Vermont Yankee. Since March of 2000 CMP has sold its power entitlement under auctions approved by the MPUC. In December 2005 the MPUC approved CMP's sale of its entitlements for various periods ranging from one to three years, through February 28, 2009. 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

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.

NYSEG, RG&E, CNG, SCG, Berkshire Gas and MNG satisfy 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 is acquired under long- and short-term supply contracts and the remainder is acquired on the spot market. Firm underground natural gas storage capacity is contracted for using long-term contracts. Firm transportation capacity is acquired under long-term contracts and is utilized to transport both natural gas supply purchased and 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 contracted for under long-term arrangements.

While none of our operating utilities were directly affected by Hurricane Katrina or Hurricane Rita, the hurricanes' effects on natural gas supply and subsequent price increases have affected our customers. Natural gas prices have risen dramatically since the hurricanes struck the Gulf Coast in late August and September 2005.

Franchises

Our operating utilities, including RG&E, 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 items

Our operating utilities, including RG&E, 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 they 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 is experimenting with programs that require utilities to actively encourage their customers to migrate to ESCO suppliers. The NYPSC may order NYSEG and RG&E to implement such programs or may seek to limit customer options by prohibiting these utilities from offering their customers a fixed price bundled service including a fixed price for supply. Such programs and policies could potentially shift commodity service to unregulated ESCOs and force our regulated utilities to be subject to competition in other services that they now provide.

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

Research and development

Our consolidated expenditures for research and development were $4 million in 2005 and $5 million each year in 2004 and 2003. RG&E's expenditures were less than $1.5 million in 2005 and $2 million each year in 2004 and 2003. 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

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.

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 $11 million, including $2.3 million by RG&E, to meet environmental requirements during the three years ended December 31, 2005. Future capital additions to meet environmental requirements are not expected to be material.

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 proposed and require that the company and RG&E update current oil SPCC plans by October 2007 and prepare new SPCC plans for locations that are covered under the regulations. These SPCC locations include electric operations service centers and substations.

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 in 2007 upon the completion of RG&E's transmission project. This closure will substantially reduce the company's emissions.

The 1990 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 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 and these methods have not been proposed by the states in which the company operates at this time.

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 those allocated to RG&E, there are few economically viable allowances available for trade.

RG&E purchases emissions allowances as necessary in order to comply with the Clean Air Act, and estimates its cost for allowances will be approximately $24 million for 2006. 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 additional capital expenditures to comply with the Clean Air Act.

Number of employees

As of January 31, 2006, Energy East had 6,114 employees, including 1,078 RG&E employees.

Financial information about geographic areas

Energy East and RG&E have no 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 on 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 business. 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.

Changes in the Northeast Electric Commodity Supply Business

: Pursuant to legislation or policy directives at the state level, our electric utilities have sold the vast majority of their generation assets. In addition, CMP has been precluded by state legislation from supplying electricity to retail customers in Maine. In New York, the NYPSC is experimenting with programs that require utilities to actively encourage their customers to migrate to ESCO suppliers. The NYPSC may order NYSEG and RG&E to implement such programs or may seek to prohibit these utilities from offering their customers a fixed price bundled service including a fixed price for supply.

See Item 7 - MD&A - Electric Delivery Rate Overview, NYSEG Electric Rate Plan Extension and Other Proceedings on the NYPSC Collaborative on End State of Energy Competition for a more detailed discussion of the proceedings related to our commodity supply business.

Federal and State Utility Regulations

: Our regulated utilities are subject to governmental regulation on a federal, state and local level. 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 decommissioning costs and 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 of any future changes or revisions to laws and regulations concerning the utility industry on our financial position, results of operation or cash flows. See Item 7 - MD&A - Electric Delivery Business Developments and Natural Gas Delivery Business Developments for a discussion of pending regulatory proceedings that could significantly affect our operations.

Holding Company Structure

: We are a holding company whose material assets are the stock of our subsidiaries and interests in joint venture entities. Accordingly, we conduct all of our operations through our subsidiaries. Our ability to pay dividends on our common stock and to pay principal and accrued interest on our debt depends on the payment of dividends to us by 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.

Natural Gas Supply

: Our natural gas companies may be affected by a number of different factors that could limit our ability to obtain natural gas supplies. While none of our operating utilities were directly affected by Hurricane Katrina or Hurricane Rita, the hurricanes' effects on natural gas supply and subsequent prices has affected our customers. Other supply and demand factors could also affect our future ability to obtain natural gas supplies. Increases in demand and lower supplies will most likely result in higher natural gas prices. While these costs are passed on to customers pursuant to natural gas adjustment clauses and therefore do not pose a direct risk to earnings, we are unable to predict what effect the sharp increase in natural gas prices may have on our customers' energy consumption or ability to pay.

Transmission

: Our electric utility companies have a substantial transmission capital investment program including an RG&E transmission project of approximately $110 million that has received the required regulatory approvals. However, the regulatory approval process for transmission projects is extensive and we may not be able to obtain the approvals required for other 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 as well as 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 in the past years regarding the transmission expansion and generation interconnection cost allocation. Changes to the rules and regulations concerning the transmission expansion and generation cost allocations may have an effect on future transmission rates.

Regional Transmission Organizations now oversee transmission services in CMP's service territory and between regions. Our transmission facilities are operated by and subject to the rules and regulations of NYISO and ISO New England. Changes to those rules and regulations could cause us to incur additional expenses in maintaining our facilities.

Operational Issues Beyond our Control

: In addition to our transmission and distribution assets, our ability to provide energy delivery and commodity services depends on the operations and facilities of third parties, including 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.

Weather

: 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.

Hedging Activities

: 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 being 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.

Commodity Price Increases

: Prices for electricity and natural gas are subject to volatile fluctuations in response to changes in supply and other market conditions. Commodity price increases are passed on to electric customers who choose a variable price option and to all natural gas customers. For the load required for electric customers who choose a fixed rate option, we have a comprehensive hedging program in place to mitigate substantially all of the price risk. Higher prices to customers can lead to higher bad debt expense and customer conservation resulting in reduced demand for our energy services.

Pension and Postretirement Benefits

: 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 pension expense. In addition, the cost to implement regulatory requirements and potential revisions to accounting standards could have an impact on our financial position, results of operations or cash flow.

Changes in Regional Economic Conditions

: Our business follows the economic cycle of the customers in the regions that we serve. A falling, slow or sluggish economy that would reduce the demand for electricity and natural gas in the areas in which we are doing business by forced temporary plant shutdowns, closing operations or slow economic growth would reduce our earnings potential in the affected region.

Federal and State Environmental Regulations

: 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. These governmental agencies require us to obtain a variety of licenses, permits, inspections and approvals. Compliance with these laws and requirements can impose significant costs, reduce cash flows, and result in plant down times.

Capital

: 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 or their ability to access the capital markets, including the commercial paper markets, could be adversely affected and our or their 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 would be the need to borrow money to pay for unexpected repairs to their transmission and distribution system caused by a catastrophic event.

Nonutility Business

: In addition to our regulated operating companies, which account for over 95% of our earnings, we own and manage several non-utility businesses that operate in a competitive environment. The customers of these businesses have a choice of suppliers. Items that may risk the future operations of these businesses include availability of capital, changes in local, state and federal laws, changes in environmental laws, commodity costs, economic conditions, weather and increased competition.

Accounting Standards

: The application of our critical accounting policies reflects complex judgments and estimates. These policies include industry specific accounting applicable to regulated public utilities and accounting for goodwill and other intangible assets, pension and other postretirement benefit plans, unbilled revenue and allowance for doubtful accounts. The adoption of new generally accepted accounting policies or changes to current accounting policies or interpretations of such policies may materially affect our financial position, results of operations or cash flows.

Item 1B. Unresolved Staff Comments

None for Energy East or RG&E.

Item 2. Properties

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

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 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 - all stations			555

(1) Cayuga Energy's 50.1% share of the generating capability.

CMP owns the following percentage 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 decommissioning in 2005, Yankee Atomic expects to complete decommissioning activities in 2006 and Connecticut Yankee expects to complete decommissioning activities 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 6,692,554 kilovolt-amperes. The transmission system consists of 2,565 circuit miles of line. The distribution system consists of 21,833 pole miles of overhead lines and 1,196 miles of direct bury and network underground lines.

NYSEG owns 438 substations in the state of New York having an aggregate transformer capacity of 15,118,000 kilovolt-amperes. The transmission system consists of 4,400 circuit miles of line. The distribution system consists of 30,382 pole miles of overhead lines and 2,009 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	-	3,699
CNG	Connecticut	-	3,623
Berkshire Gas	Massachusetts	-	727
MNG	Maine	2	80
New Hampshire Gas (Propane air)	New Hampshire	-	28

NYSEG owns the Seneca Lake Natural Gas Storage Facility that is able to store approximately 1.4 billions of cubic feet of natural gas. As of December 31, 2005, this facility was at approximately 50% of capacity.

A portion of our utility plant is subject to liens or mortgages securing 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 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 2000 NYSEG and Penelec received a new source review letter from EME Homer City Generation, L.P., a subsidiary of the purchaser of the Homer City generating station in which NYSEG and Penelec each formerly owned a one-half interest. The letter gave NYSEG and Penelec notice that the EPA has found alleged violations of the Federal Clean Air Act related to the Station. EME Homer City Generation, L.P. has indicated that it will claim that certain fines, penalties and costs arising out of or related to these alleged violations, which NYSEG believes may be material, are liabilities retained by NYSEG and Penelec under the terms of the Asset Purchase Agreement for the Station. While NYSEG will continue to examine this matter, it believes that such fines, penalties and costs are not liabilities retained by it.

(b) 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, scheduled to be shut down in 2007, 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. RG&E, the NYSDEC and the Attorney General last discussed this matter in August 2005. RG&E is not able to predict the outcome of this matter.

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

None for Energy East or RG&E.

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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, 2005.

Energy East Corporation

Name and Position	Age	Period served	Business experience - January 2001 to date
Wesley W. von Schack Chairman, President &Chief Executive Officer	61	to date	Chairman, President & 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 Vice President and Chief Administrative Officer	48	2005 to date 2004 to 2005 to 2004	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 Vice President, Controller & Chief Accounting Officer	44	2005 to date 2002 to 2005 to 2002	Vice President, Controller & Chief Accounting Officer Vice President, Treasurer & Secretary Vice President and Treasurer
F. Michael McClain Vice President - Finance, Treasurer & Chief Integration Officer	56	2005 to date 2003 to 2005 to 2003	Vice President - Finance, Treasurer & 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.	61	2006 to	Vice President - General Counsel Partner - LeBoeuf, Lamb, Greene & MacRae LLP

Vice President - General Counsel		date to 2005	
Angela M. Sparks-Beddoe Vice President, Public Affairs of Energy East Management Corporation	41	2001 to date to 2001	Vice President, Public Affairs of Energy East Management Corporation Director, Legislative Affairs of New York State Electric & Gas Corporation

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

Name and Position	Age	Period served	Business experience - January 2001 to date
James P. Laurito President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation	49	2005 to date 2004 to 2005 2003 to 2004 to 2003	President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation President of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation President and Treasurer of New York State Electric & Gas Corporation President and Chief Operating Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company

Central Maine Power Corporation

Name and Position	Age	Period served	Business experience - January 2001 to date
Sara J. Burns President and Chief Executive Officer of Central Maine Power Company	50	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 2001 to date
Robert M. Allessio 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	55	2005 to date	President and Chief Executive Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company
		2004 to date	Chairman and Chief Executive Officer of The Berkshire Gas Company
		2004 to 2005	Executive Vice President and Chief Operating Officer of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company
		2003 to 2004	Senior Vice President, Operating Services of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company
		2001 to 2004	President, Chief Executive Officer and Treasurer of The Berkshire Gas Company
		2001 to 2003	Vice President, Operating Services of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company
Karen L. Zink President, Treasurer & Chief Operating Officer of The Berkshire Gas Company	48	2004 to date	President, Treasurer & Chief Operating Officer of The Berkshire Gas Company
		2003 to 2004	Vice President and General Manager of The Berkshire Gas Company
		2001 to 2003	Vice President of The Berkshire Gas Company

Wesley W. von Schack has an employment agreement for a term ending June 30, 2008. 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 31,264 at January 31, 2006. See Item 8 - Note 16 to our Consolidated Financial Statements for information regarding high and low stock prices and dividends declared.

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, 2005, 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)	3,159,988	$23.81	7,296,830
Equity Compensation Plan Not Approved by Stockholders (Restricted Stock Plan) [1]	N/A	N/A	1,268,607
Total	3,159,988		8,565,437

[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, 2005 to October 31, 2005)	2,924(1)	$25.60	-	-
Month #2 (November 1, 2005 to November 30, 2005)	4,986(1)	$23.44	-	-
Month #3 (December 1, 2005 to December 31, 2005)	5,004(1)	$23.36	-	-
Total	12,914	$23.90	-	-

(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, 2005.

Item 6. Selected Financial Data

See the information under the heading Selected Financial Data for each registrant, which is included in this report as follows:

Energy East - page II-21
RG&E - page II-87

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 each registrant, which is included in this report as follows:

Energy East - pages II-22 to II-50
RG&E - pages II-87 to II-95

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Item 8. Financial Statements and Supplementary Data

Index to 2005 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, 2005.

Energy East management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2005, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page II-84.

Changes in Internal Control over Financial Reporting

There were no 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

	2005	2004	2003	2002 [1]	2001
(Thousands, except per share amounts)					
Operating Revenues	$5,298,543	$4,756,692	$4,514,490	$3,778,026	$3,681,613
Depreciation and amortization	$277,217	$292,457	$299,430	$240,306	$202,721
Other taxes	$246,271	$252,860	$269,238	$229,158	$192,345
Interest Charges, Net	$288,897	$276,890	$284,482	$256,161	$216,387
Income from Continuing Operations	$256,833	$237,621	$208,490	$189,929	$188,739
Net Income	$256,833	$229,337	$210,446	$188,603 (2)	$187,607 (3) (4)
Earnings per Share from Continuing Operations, basic	$1.75	$1.63	$1.43	$1.45 [2]	$1.62 [3]
Earnings per Share from Continuing Operations, diluted	$1.74	$1.62	$1.43	$1.45 [2]	$1.62 [3]
Earnings per Share, basic	$1.75	$1.57	$1.45	$1.44 (2)	$1.61 (3)
Earnings per Share, diluted	$1.74	$1.56	$1.44	$1.44 (2)	$1.61 (3)
Dividends Paid per Share	$1.115	$1.055	$1.00	$.96	$.92
Average Common Shares Outstanding, basic	146,964	146,305	145,535	131,117	116,708
Average Common Shares Outstanding, diluted	147,474	146,713	145,730	131,117	116,708
Capital Spending	$331,294	$299,263	$289,320	$229,387	$222,875
Total Assets	$11,487,708	$10,796,622	$11,330,441	$10,944,347	$7,269,232 (5)
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	$3,667,065	$3,797,685	$4,017,846	$3,721,959	$2,816,278

(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.
(3) Includes the writedown of our investment in NEON Communications, Inc. that decreased net income $46 million and EPS 39 cents.

(4) Includes goodwill amortization of $25 million.
(5) Does not reflect the reclassification of accrued removal costs from accumulated depreciation to a regulatory liability.

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, RG&E, CMP and Berkshire Gas that currently provide for sharing of achieved savings among customers and shareholders, allow for recovery of certain costs including stranded costs, and provide stable rates for customers and revenue predictability. CNG is currently operating under existing rates from an incentive rate plan that expired in September 2005, with no earnings sharing. SCG received approval for new rates that became effective January 1, 2006. As of January 31, 2006, Energy East had 6,114 employees.

We continue to focus our strategic efforts in the areas that have the greatest effect on customer satisfaction and shareholder value. In doing this, management has implemented a company-wide restructuring effort that focuses on efficiently providing utility support services. In 2004 we formed Utility Shared Services Corporation to consolidate support services functions for our operating utilities.

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 operations, although their outcomes are difficult to predict. Those proceedings, which are discussed below, could affect the nature of the electric and natural gas utility industries in New York and New England.

The continued evolution of the electric utility industry is evidenced by the recent enactment of the Energy Policy Act of 2005, which repealed the Public Utility Holding Company Act of 1935 (PUHCA). With the repeal of PUHCA, the FERC and state utility commissions have new authority to regulate and monitor, among other things, intercompany cost allocations of holding companies such as Energy East.

We engage in various investing and financing activities to meet our strategic objectives. Our primary goal for investing activities is to maintain a reliable energy delivery infrastructure. We fund our investing activities primarily with internally generated funds. We plan to invest nearly $2 billion in our energy delivery infrastructure during the next five years, including approximately $900 million dedicated to electric reliability. We focus our financing activities on maintaining adequate liquidity and credit quality and minimizing our cost of capital.

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. We have sold a majority of our noncore businesses and the last of our substantial regulated generation assets and we continue to invest in infrastructure that supports our electric and natural gas delivery systems. Achieving operating excellence and efficiencies throughout the company is central to our strategy.

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

Energy East Corporation

Our long-term rate plans continue to be 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 the companies to earn a fair return while minimizing price increases and sharing achieved savings with customers.

Electric Delivery Rate Overview

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

: The current NYSEG rate plan was approved by the NYPSC February 2002 Order, which provides 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 is required to use the lower of its actual equity or a 45% equity ratio. At December 31, 2005, the equity NYSEG uses for earnings sharing approximates $740 million, which is based on the 45% equity ratio limitation. Earnings levels were sufficient to generate estimated pretax sharing with customers of $22 million in 2005 and $17 million in 2004.

RG&E's current rates were established by the 2004 Electric Rate Agreement, which addresses RG&E's electric rates through 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 is 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 $23 million of pretax sharing in 2005. There was no sharing in 2004.

NYSEG's and RG&E's current electric rate plans 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 market price of electricity and an option to purchase electricity supply from an ESCO. RG&E customers make their supply choice annually. NYSEG customers make their election every two years, most recently in late 2004 for the 2005 and 2006 plan years. RG&E customers who do not make a choice are served under RG&E's variable price option. NYSEG customers who do not make a choice are served under the fixed rate option. Both NYSEG's and RG&E's customers also pay nonbypassable wires charges, which include recovery of stranded costs. Approximately 45% of NYSEG's and 75% of RG&E's total electric load is now provided by an ESCO or at the market price.

In March 2000 the NYPSC instituted the Collaborative on End State of Energy Competition proceeding to address the future of competitive electric and natural gas markets, including the role of regulated utilities in those markets. Other objectives of the proceeding include identifying and suggesting actions to eliminate obstacles to the development of those competitive markets

and providing recommendations concerning provider of last resort and related issues. NYSEG and RG&E believe that the NYPSC should not adopt a single end-state vision for New York and should maintain flexibility by addressing each utility in the context of that utility's unique circumstances.

In August 2004 the NYPSC issued a Policy Statement recommending that all potentially competitive utility functions be opened to competition. While it is not possible to determine when markets will become workably competitive, all utilities were required to prepare plans to foster the development of retail energy markets. The plans vary by individual utility and NYSEG and RG&E do not expect the statement of policy to affect their commodity service options under their current electric rate plans, which extend through December 31, 2006, for NYSEG and December 31, 2008, for RG&E.

NYSEG and RG&E filed their retail access plans with the NYPSC on April 14, 2005. As part of its filing, NYSEG proposed to continue offering its current commodity options to customers, with new two-year commodity offerings beginning January 1, 2007, that are the same as its current program except for the addition of a program to facilitate ESCO market participation by allowing NYSEG to bill and collect from ESCO customers directly. In June and July 2005 parties filed comments both in support of and in opposition to NYSEG's and RG&E's retail access plans. NYSEG's proposal is consistent with the commodity options included in its recently filed Electric Rate Plan Extension.

NYSEG and RG&E believe that their current commodity option programs are the most comprehensive in New York State, providing a full menu of electric supply choices, including a fixed price option for customers who do not want to be subjected to volatile wholesale electricity prices. Experience has shown that the vast majority of customers want their utility to remain a supply option and prefer a fixed price option. NYSEG and RG&E believe that their programs are also 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 $100 million in customer benefits through 2005.

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 2005 and 2006 and 2.9% in 2007. Price adjustments have resulted in rate decreases in each year that the agreement has been in effect since 2002.

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-recommended base level ROE of 10.72%, plus a 50 basis point adder for regional facilities. The formula rates are updated annually in a filing to the FERC on June 1st. CMP's transmission rates increased approximately $15 million for the year effective July 1, 2005. The increase enables CMP to recover its share of ISO New England regional transmission costs and its local transmission costs.

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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 Plan Extension

: On September 30, 2005, NYSEG filed a six-year Electric Rate Plan Extension with the NYPSC, to commence on January 1, 2007, which is the day after the end of its current rate plan. As part of its filing, NYSEG proposed to decrease customers' bills prior to the commencement of the Electric Rate Plan Extension by implementing a bill credit to customers effective for the four-month period from September 1, 2006 through December 31, 2006. In particular, NYSEG proposed to return to its electric customers $23.7 million from its ASGA, which was initially created as a result of the sale of NYSEG's generating stations. The ASGA has been enhanced during NYSEG's current rate plan with the customers' share of excess earnings. Beginning on January 1, 2007, NYSEG also proposed to reduce its nonbypassable wires charge by $162.8 million and increase delivery rates by $91.6 million, thus maintaining an annualized overall electricity delivery rate decrease of approximately $71.2 million, or 9.5%. NYSEG proposed to accomplish the reduction in the nonbypassable wires charge, which would more than offset the increase in delivery rates, by accelerating benefits from the expiration of certain above-market NUG contracts and capping the amount of above-market NUG costs over the term of the rate plan extension, also known as NYSEG's NUG levelization proposal. NYSEG also proposed to increase its equity ratio from 45% to 50%. In addition, NYSEG's proposal would allow customers to continue to benefit from merger synergies and savings.

On October 28, 2005, NYSEG filed a motion with the NYPSC asking that the chairman of the NYPSC recuse himself from any consideration of NYSEG's Electric Rate Plan Extension filing and of NYSEG's proposed Retail Access Plan filed in April 2005. The motion maintained that the chairman's recusal is necessary because his public statements demonstrate that he is biased against NYSEG and its Voice Your Choice program, in violation of NYSEG's due process rights for a fair and impartial adjudication. The chairman denied the motion on December 7, 2005.

On January 9, 2006, NYSEG filed with the NYPSC revisions and updates to its September 30, 2005 filing. By this filing, NYSEG proposed to further reduce its nonbypassable wires charge by an additional $5 million for a total reduction of $167.8 million, and proposed to further increase its delivery rates by an additional $12 million for a total increase of $103.6 million. As a result of these revisions and updates, NYSEG's proposed annualized overall electricity delivery rate decrease was reduced by $7 million, to $64.2 million, or 8.6%. These revisions and updates did not change the overall framework of NYSEG's Electric Rate Plan Extension proposal.

On January 16, 2006, two ESCOs submitted a motion to the ALJ to dismiss the portion of NYSEG's rate filing requesting NYPSC approval of the commodity option program. The Consumer Protection Board and the Public Utility Law Project opposed that motion in their responses filed with the NYPSC on January 19 and 30, 2006, respectively. NYSEG filed its

opposition to the motion with the NYPSC on January 25, 2006. NYSEG stated in its filing that the motion is not supported by law, would deny NYSEG due process, including an evidentiary hearing, and distorts the evidence presented by NYSEG regarding the Voice Your Choice program. The ALJ denied the ESCOs' motion in a Ruling issued on February 10, 2006. In the Ruling, the ALJ concluded that the NYPSC's August 2004 Policy Statement was not intended as a binding order and, as a matter of law, does not preclude NYSEG's proposal to extend its Voice Your Choice program. The ALJ also determined that NYSEG's Electric Rate Plan Extension proceeding is the proper forum for consideration of issues presented by NYSEG's proposal to extend its Voice Your Choice program.

In early February 2006, Staff of the NYPSC (Staff) and six other parties submitted their direct cases. Staff presented a one-year rate case only. In its presentation, Staff proposed an overall delivery rate decrease of approximately $82.8 million, or about 13.4%, for the 2007 rate year. Staff neither rebutted nor addressed NYSEG's six-year rate plan extension proposal, including NYSEG's NUG levelization proposal. Staff also opposed NYSEG's proposal to extend its Voice Your Choice program.

NYSEG filed its rebuttal case on February 21, 2006, responding to Staff's one-year rate case proposal by proposing to increase delivery rates commencing January 1, 2007, by approximately $58.3 million, which would be offset by an equal amortization of the ASGA back to customers. NYSEG also proposed to amortize an equivalent portion of the ASGA liability through a bill credit in the nonbypassable wires charge to offset the delivery increase, resulting in no change in 2007. Although NYSEG's rebuttal testimony responds to Staff's one-year rate case proposal, NYSEG continues to support the adoption of a six-year rate plan extension proposal, including its NUG levelization proposal to moderate the delivery rate increase and its proposal to extend the Voice Your Choice program.

Hearings are scheduled to commence on March 22, 2006. NYSEG cannot predict the outcome of this proceeding.

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 following the shutdown of RG&E's 257 MW coal-fired Russell Station, which is expected to occur in 2007. 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 is expected to begin in the first quarter of 2006. The estimated cost of the project is approximately $110 million.

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 operating 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 the companies are allocated an aggregate of over 360 MWs of Niagara Power Project power 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 license. The annual value of the Niagara allocation to the companies

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at current electricity market prices, is approximately $100 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 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.

NYSEG and RG&E filed a motion to intervene in the relicensing proceeding on November 3, 2005, and on December 16, 2005, NYSEG and RG&E submitted comments arguing that the FERC should: (1) consider power allocation issues (including to NYSEG and RG&E) in its review of the application; (2) require the NYPA to update the record with information concerning the benefits of the allocation to NYSEG and RG&E customers; and (3) require the NYPA to meet with NYSEG and RG&E to discuss their allocations and the effects of withdrawal of the allocations on their customers. On January 3, 2006, the NYPA filed an answer arguing that certain issues raised in our comments should be ignored by the FERC and that allocation issues are not an appropriate question in the relicensing proceeding. On January 10, 2006, NYSEG and RG&E filed a response to NYPA's answer. We are unable to predict the outcome of this proceeding.

CMP Alternative Rate Plan

: On December 7, 2005, CMP and the Office of the Public Advocate filed with the MPUC a stipulation for an extension of CMP's ARP 2000. This stipulation is also supported by low-income customer advocates and a coalition of industrial energy customers has signed the stipulation agreement. The stipulation maintains the provisions of CMP's ARP 2000 and proposes a three-year extension with four additional items. The stipulation provides for a 0.5% increase in the scheduled productivity offset for July 2006 and provides for productivity offsets averaging 2% for 2008, 2009 and 2010. The stipulation adds $2.2 million in assistance for low income customers annually starting in 2006. Under the stipulation, CMP agrees to educate its customers on the regional benefits of adjusting usage during peak hours and demand periods and also agrees to limit the promotion of increased usage during specified higher demand periods. Finally, CMP agrees to commit to investing an additional $25 million through 2010 for enhancements to the reliability, safety and security of its distribution system.

On February 1, 2006, the MPUC approved that portion of the stipulation increasing assistance to low income customers. The MPUC has established a schedule to review the remaining terms of the stipulation, and its decision is expected in the second quarter of 2006. CMP cannot predict the outcome of this proceeding.

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 2006, 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 included costs through 2010, the earliest year the DOE expects that it will begin removing fuel. The Yankee companies' damage claims through 2002 totaled approximately $263 million and CMP's sponsor-weighted share is approximately $45 million. The claims also note additional costs that will be incurred for each year that fuel remains at the sites beyond 2010. If the Yankee companies prevail in these cases, any damages awarded would be credited to their respective decommissioning or spent fuel trust funds. Any remaining trust funds would be returned to electric customers when decommissioning is complete. The Yankee companies expect a trial court decision in the first half of 2006. CMP cannot predict the outcome of this litigation.

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. Bechtel filed a lawsuit in Connecticut state court challenging that termination and Connecticut Yankee filed a counterclaim to recover damages caused by Bechtel's breach of contract and termination. Any amount that Connecticut Yankee recovers from Bechtel would be credited to its decommissioning costs and any remaining decommissioning funds would be returned to electric customers when decommissioning is complete. This matter is scheduled for trial in mid-2006 and CMP cannot predict the outcome of this litigation.

The FERC authorized Connecticut Yankee to begin collecting the revised decommissioning charges in January 2005 from Connecticut Yankee's owners, including CMP, whose share of a $93 million increase is approximately $6 million. Under Maine statutes, CMP is allowed to recover any increases in decommissioning costs and pursuant to the January 2005 stranded cost settlement, CMP began collecting the higher Connecticut Yankee decommissioning costs through rates in March 2005. (See Item 7 - MD&A - Electric Delivery Rate Overview.)

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In June 2004 the DPUC and the OCC filed a petition with the FERC asking it to determine if any of Connecticut Yankee's increased decommissioning costs were not prudently incurred. In August 2004 the FERC issued an initial Order rejecting the DPUC's petition; approved a rate increase for Connecticut Yankee effective February 1, 2005, subject to refund; and set for hearing the costs to be recovered. The DPUC requested rehearing of the FERC's August 2004 Order and on October 20, 2005, the FERC issued an order denying the request for rehearing. In December 2005 the DPUC filed a notice of appeal of the initial August 2004 Order with the United States Court of Appeals, District of Columbia Circuit.

The DPUC has alleged to the FERC that Connecticut Yankee imprudently managed and wrongfully terminated Bechtel, the turnkey decommissioning contractor, and as a result, concludes that approximately $225 million to $235 million of Connecticut Yankee's rate increase should be denied. The FERC Staff and Bechtel also allege that the cost increase was imprudently incurred. On November 22, 2005, the FERC's ALJ issued an Initial Decision that found in favor of Connecticut Yankee on all imprudence claims, finding that no disallowance was warranted. Because the ALJ found that Connecticut Yankee had refuted all claims of imprudence, the ALJ did not address any party's proposed disallowance. The interveners who unsuccessfully raised imprudence claims before the ALJ have taken exception to the ruling before the FERC, which is expected to issue a final decision in 2006. CMP is unable to predict the outcome of this proceeding.

Nonutility Generation

: We expensed approximately $631 million for NUG power in 2005 and we estimate that our combined NUG power purchases will total $571 million in 2006, $575 million in 2007, $410 million in 2008, $244 million in 2009 and $83 million in 2010. 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 2005, averaged 10.0 cents per kilowatt-hour for CMP and 10.2 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's stranded cost rates and in NYSEG's current electric rate plan through a nonbypassable wires charge. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

Other Proceedings on the NYPSC Collaborative on End State of Energy Competition

: NYSEG and RG&E have supplied comments in NYPSC proceedings regarding other investor-owned utility programs that are designed to encourage customers to migrate from utilities to ESCOs. NYSEG and RG&E believe that the "PowerSwitch" program implemented by Orange and Rockland Utilities, Inc., which is being touted as a model for the rest of the state, is flawed, since it results in customers being switched to ESCOs without complete information on the program. In their filing, NYSEG and RG&E question whether the "PowerSwitch" program is consistent with the NYPSC's Uniform Business Practices. NYSEG and RG&E believe the program results may be suspect and should not be used as a basis to expand the program to other utilities. On June 1, 2005, the NYPSC approved Central Hudson Gas & Electric Corporation's retail access plan and rejected NYSEG's and RG&E's comments requesting the NYPSC to not take action on Central Hudson's plan and to suspend the development of new retail access initiatives that are based on flawed models.

In a related matter, on July 26, 2005, the NYPSC issued a notice soliciting comments on an NYPSC Staff proposal on statewide guidelines for ESCO Referral Programs. As a result of experience gained since the Policy Statement was issued in August 2004, the NYPSC Staff has identified a need for statewide simplicity, consistency and uniformity, to the extent practicable, in ESCO Referral Programs. In September and October 2005 NYSEG and RG&E filed comments urging rejection of the proposal and objecting to the proposal to the extent that it will require all utilities to adopt a "PowerSwitch" type program. At its session on December 14, 2005, the NYPSC established procedures for utilities to follow in implementing ESCO Referral Programs based on the Orange & Rockland model for those programs, as modified and enhanced with additional consumer protection measures. The NYPSC also approved, with modifications, Central Hudson's proposed ESCO Referral Program. The NYPSC ordered RG&E to begin a collaborative with interested parties for the purpose of implementing an ESCO Referral Program at RG&E. The NYPSC further permitted NYSEG to address the ESCO Referral Program within the context of its current rate case described above. Based on these latest developments, it is unclear whether or not NYSEG will be able to extend its Voice Your Choice program as a part of its ongoing electric rate proceeding.

New England RTO

: In March 2004 the FERC issued an order that accepted a six-state New England RTO as proposed by ISO New England and the New England transmission owners. As an RTO, ISO New England 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 developed by an RTO. The New England transmission owners have appealed the application of the adders to regional facilities to the Circuit Court of Appeals for the District of Columbia. Other parties have appealed the FERC's decision to grant the adders to regional facilities. The appeals are pending before the Court and no decision is expected until mid-2006. The FERC order also accepted, subject to suspension and hearing, the New England transmission owner's proposed base level ROE of 12.8% applicable to rates for local and regional transmission service. Those rates became effective, subject to refund, February 1, 2005. The FERC conducted evidentiary hearings on the final base level ROE and the incentive for new transmission investment in January and February 2005, and issued an initial decision in May 2005 recommending a base level ROE of 10.72%, plus the 50 basis point adder for regional facilities. The New England transmission owners have filed exceptions to the initial decision both with respect to the base level ROE and also seeking application of the 100 basis point adder for new investments applicable to both the local and regional transmission rates. A final decision from the FERC on those issues is not expected until early 2006. The New England transmission owners and ISO New England implemented the New England RTO effective February 1, 2005.

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.

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The FERC issued an order directing the NYISO to modify certain energy prices for May 8 and 9, 2000, and to back bill NYISO market participants, including NYSEG and RG&E. The NYISO and many market participants filed requests for rehearing with the FERC concerning that order. While the FERC has not ruled on those requests for rehearing, on July 8, 2005, and October 7, 2005, the NYISO issued back billings that reflected the FERC order concerning the May 2000 issues. NYSEG's updated back billing relating to May 8 and 9, 2000, was approximately $2 million and RG&E's was approximately $1 million. In the third quarter of 2005 NYSEG and RG&E deferred the amounts associated with the back billings as regulatory mandates, pursuant to their Electric Rate Agreements approved by the NYPSC.

Locational Installed Capacity Markets

: In 2003 the FERC required ISO New England 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 New England developed and filed with the FERC a LICAP market proposal based on an administratively set demand curve. In June 2005 the FERC ALJ issued an initial decision essentially adopting the ISO New England LICAP market proposal with minor modifications. CMP and other parties that oppose the ISO New England LICAP 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 LICAP proposal in the recommended decision. In addition, the MPUC, CMP, the DPUC representing the state of Connecticut and the OCC, joined with several Massachusetts parties and filed briefs with the FERC asking that the parties conduct settlement discussions to consider alternatives and that the FERC consider other alternatives to the LICAP market proposal. In response to these protests, the FERC has delayed any possible implementation of LICAP until October 1, 2006, at the earliest and granted oral arguments to consider opposition to LICAP and possible alternatives. Following oral arguments, the FERC granted the request to conduct settlement discussions to consider alternatives. The discussions began in November 2005 and on January 31, 2006, the Settlement ALJ reported to the FERC that most of the parties had reached an agreement in principle on an alternative to LICAP. This alternative will be filed with the FERC by April 12, 2006, and thereafter parties will be allowed to submit comments or opposition before the FERC issues a decision. CMP will review and evaluate the settlement as filed with the FERC. Presently, CMP and the MPUC, among other parties, are opposed to the LICAP proposal and the alternative, as either proposal could have an adverse effect on Maine's economy by increasing rates 5% to 10%. Maine lawmakers are holding hearings in early 2006 on the possibility of Maine withdrawing from ISO New England. CMP cannot predict the outcome of these settlement discussions, how the FERC will rule or what modifications the FERC might make to the filing. Any increase in costs associated with LICAP or any negotiated alternative will be reflected in Maine's standard offer rates.

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 Instituting Safety Standards also denies utility requests for recovery of implementation costs and establishes criteria for utilities seeking authorization to recover costs as an incremental expense. 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 addition, NYSEG and RG&E filed a separate petition for rehearing dealing with the recovery of incremental costs of complying with 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 have begun to implement 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. NYSEG and RG&E have incurred costs of approximately $3 million as of December 31, 2005, including more than $1 million incurred by RG&E. RG&E estimates that it will incur additional costs of approximately $3 million, and NYSEG estimates it will incur another approximately $9 million of costs, by the end of 2006 to comply with the order.

Hurricanes' Effects on Natural Gas Supply

: While none of our operating utilities were directly affected by Hurricane Katrina or Hurricane Rita, the hurricanes' effects on natural gas supply and subsequent price increases, including wholesale electricity prices, have affected our electricity customers. Electricity prices for customers who elected variable rate options have risen dramatically since the hurricanes struck the Gulf Coast in late August and September 2005. Current prices remain high due to economic conditions. We are unable to predict what effect the sharp increase in natural gas prices may have on wholesale electricity prices and our customers' energy consumption or ability to pay.

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 11.5% for the 27-month period ended December 31, 2004, and in excess of 12.5% for each of the calendar years from 2005 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 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 2005 or 2004. The ROE target can be increased to 12.25% if certain incentive targets are met.

SCG's current rates became effective on January 1, 2006, pursuant to a settlement agreement that will be 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. (See Item 7 - MD&A - Natural Gas Delivery Business Developments.)

On March 29, 2005, CNG responded to a DPUC request pertaining to the September 30, 2005, expiration of CNG's IRP. CNG notified the DPUC that CNG's existing rates would continue in effect after the expiration of the IRP, but the earnings sharing mechanism, the rate stay-out commitment, the exogenous cost provision and provisions involving merger-enabled gas cost savings would no longer be applicable.

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. This plan has no ROE cap and has an annual inflationary rate adjustment that is determined through the formula of the gross domestic product minus 1% as a productivity offset. The adjustment is made on September 1st each year.

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, effective April 1, 2004, that provides the companies the right to acquire natural gas supply and optimizes transportation and storage services.

Other Proceedings on the NYPSC Collaborative on End State of Energy Competition: See Electric Delivery Business Developments.

SCG Regulatory Proceeding

: SCG's IRP expired on September 30, 2005. SCG filed a rate case on April 29, 2005, as a result of a DPUC decision in October 2004 to deny recovery of approximately $21 million of exogenous costs that included qualified pension and other postretirement benefits, taxes, uncollectible expense and SCG's Customer Hardship Arrearage Forgiveness Program. SCG requested approximately $35 million of additional revenues, or an increase of approximately 11% compared with revenues based on current rates. On December 28, 2005, the DPUC approved a settlement agreement and allowed an annual revenue increase of $26.7 million or 8.4%. The rate increase includes approximately $5 million annually for six years for recovery of amounts previously deferred under SCG's Customer Hardship Arrearage

Forgiveness Program and its Three-Way Payment Plan and approximately $12 million for uncollectible expense. The DPUC approval allows for an ROE of 10% effective from January 1, 2006, through December 31, 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. Motions to end the RG&E action are pending and discovery is ongoing in the NYSEG action. 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.

Hurricanes' Effects on Natural Gas Supply

: While none of our operating utilities were directly affected by Hurricane Katrina or Hurricane Rita, the hurricanes' effects on natural gas supply and subsequent price increases have affected our customers. Natural gas prices have risen dramatically since the hurricanes struck the Gulf Coast in late August and September 2005. Current prices remain high due to economic conditions. We are unable to predict what effect the sharp increase in natural gas prices may have on our customers' energy consumption or ability to pay.

Other Businesses

South Glens Falls Energy Bankruptcy Filing

: 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, owns 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.

Other Matters

New Accounting Standards

Statement 123(R)

: In December 2004 the FASB issued Statement 123(R), which is a revision of Statement 123. Statement 123(R) 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

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Statement 123(R) did not have a material effect on our financial position, results of operations or cash flows as of December 31, 2005. (See Item 8 - Note 1 and Note 12 to our Consolidated Financial Statements.)

FIN 47

: In March 2005 the FASB issued FIN 47, which 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, as required. Our application of FIN 47 did not have a material effect on our financial position, results of operations or cash flows. (See Item 8 - Note 1 to our Consolidated Financial Statements.)

Contractual Obligations and Commercial Commitments

At December 31, 2005, our contractual obligations and commercial commitments are:

	Total	2006	2007	2008	2009	2010	After 2010
(Thousands)							
Contractual Obligations							
Long-term debt[(1)]	$6,256,836	$537,061	$449,105	$274,979	$321,626	$423,473	$4,250,592
Capital lease obligations[(1)]	56,211	4,337	4,145	4,145	4,172	4,171	35,241
Operating leases	64,504	12,473	11,409	8,384	7,252	7,717	17,269
Nonutility generator power purchase obligations	2,434,653	571,225	575,168	409,730	244,463	83,446	550,621
Nuclear plant obligations	289,262	37,802	33,574	29,565	21,557	19,383	147,381
Unconditional purchase obligations:							
Electric	2,330,230	343,947	331,075	289,727	292,692	309,481	763,308

Natural gas	276,962	96,596	84,180	66,241	17,651	7,074	5,220
Pension and other postretirement benefits[2]	2,184,598	177,586	184,576	193,351	203,821	214,585	1,210,679
Other long-term obligations	12,954	3,942	3,199	1,640	1,674	1,387	1,112
Total Contractual Obligations	$13,906,210	$1,784,969	$1,676,431	$1,277,762	$1,114,908	$1,070,717	$6,981,423

[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, 2005.
[2] Amounts are through 2015 only.

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Critical Accounting Estimates

In preparing the 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 estimates 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.

Statement 71

: 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 expense or revenue certain regulatory assets and 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 2005 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.

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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, 2005, we decreased the discount rate from 5.75% to 5.50%. 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. During the third quarter of 2005 we re-examined the set of estimates used for all the operating companies and determined that some operating companies required changes to the assumptions used in determining their unbilled revenue estimates. (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.)

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Liquidity and Capital Resources

Cash Flows

The following table summarizes our consolidated cash flows for 2005, 2004 and 2003.

Year Ended December 31,	2005	2004	2003
(Thousands)			
Operating Activities			
Net income	$256,833	$229,337	$210,446
Noncash adjustments to net income	422,635	431,700	482,345
Changes in working capital	(98,309)	(227,726)	(127,610)
Other	(80,887)	(94,211)	(89,414)
Net Cash Provided by Operating Activities	500,272	339,100	475,767
Investing Activities			
Sale of generation assets	-	453,678	-
Excess decommissioning funds retained	-	76,593	-
Utility plant additions	(331,294)	(299,263)	(289,320)
Current investments available for sale	(57,270)	(135,655)	-
Other	20,133	1,600	26,740
Net Cash (Used in) Provided by Investing Activities	(368,431)	96,953	(262,580)
Financing Activities			
Net issuance of common stock	(3,838)	(2,988)	4,234
Net (repayments of) increase in debt and preferred stock of subsidiaries	30,908	(333,095)	(239,745)
Dividends on common stock	(150,367)	(136,374)	(127,940)
Net Cash Used in Financing Activities	(123,297)	(472,457)	(363,451)
Net Increase (Decrease) in Cash and Cash Equivalents	8,544	(36,404)	(150,264)
Cash and Cash Equivalents, Beginning of Year	111,465	147,869	298,133
Cash and Cash Equivalents, End of Year	$120,009	$111,465	$147,869

The total of cash flows from operating and investing activities in 2005 was $132 million as compared to $436 million in 2004 and $213 million in 2003. The decrease of $304 million in 2005 and increase of $223 million in 2004 was primarily due to the sale of Ginna in 2004, which resulted in cash proceeds and retention of excess decommissioning funds that totaled $530 million. (See Item 8 - Note 2 to our Consolidated Financial Statements.) The decrease in 2005 was partially offset by an increase in net cash provided by operating activities of $161 million. The increase in 2004 was partially offset by a $100 million increase in working capital expenses.

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Operating Activities Cash Flows

: Net cash provided by operating activities was $500 million in 2005 compared to $339 million in 2004 and $476 million in 2003. The major issues that contributed to the $161 million increase in cash provided by operating activities for 2005 were:

- 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 $95 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 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 $34 million in pension contributions.

The $137 million decrease in net cash provided by operating activities in 2004 was primarily due to:

- The $60 million of net proceeds from the sale of Ginna that was refunded to RG&E customers in 2004 as provided in RG&E's Electric Rate Agreement.
- Increased tax payments of $74 million primarily due to the elimination of deferred tax liabilities due to the sale of Ginna.
- Increased expenditures of $44 million to replenish natural gas inventories.

Investing Activities Cash Flows

: Net cash used in investing activities was $368 million in 2005 compared to net cash provided by investing activities of $97 million in 2004 and net cash used in investing activities of $263 million in 2003. The $465 million decrease in 2005 and the $360 million increase in 2004 were primarily due to effects of the sale of Ginna in 2004.

Capital spending totaled $331 million in 2005, $299 million in 2004, and $289 million in 2003, including nuclear fuel for RG&E in 2004 and 2003. 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, and a new customer care system for NYSEG.

Capital spending is projected to be $442 million in 2006, is expected to be paid for principally with internally generated funds and will be primarily for the same purposes described above, as well as the RG&E transmission project, on which construction will begin in the first quarter of 2006. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

Financing Activities Cash Flows

: Net cash used in financing activities was $123 million in 2005 compared to $472 million in 2004 and $363 million in 2003. 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. For 2004, the $109 million increase was the result of higher net repayments of debt and preferred stock primarily due to funds available from the sale of Ginna.

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Capital Structure at December 31,	2005	2004	2003
Long-term debt(1)	54.6%	54.8%	55.0%
Short-term debt(2)	1.8%	3.3%	4.6%
Preferred stock	0.4%	0.7%	1.8%
Common equity	43.2%	41.2%	38.6%
	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 2005 and early 2006 included:

- Raising our common stock dividend 5.5% in October 2005 to a new annual rate of $1.16 per share.
- Issuing 607,342 shares of company common stock in 2005, at an average price of $26.46 per share, through our Investor Services Program. The shares were original issue shares.
- Awarding 265,406 shares of our common stock in 2005, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $26.42 per share of common stock awarded.
- Awarding 248,320 shares of our common stock in February 2006, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.83 per share of common stock awarded.

During the first quarter of 2005, NYSEG auctioned $100 million of Series 2004C pollution control revenue bonds for a period of five years through January 2010, at 3.245%. NYSEG also converted $60 million of Series 1985A pollution control revenue bonds from an annual-term put mode to a fixed rate of 4.10% through maturity on March 15, 2015. In May 2005 NYSEG refunded a $65 million 6.15% fixed-rate tax-exempt pollution control note with proceeds from the issuance of $65 million of multi-mode tax-exempt pollution control notes due in 2026.

In March 2005 CMP redeemed at par $25 million of its Series E, 8.125% medium-term notes with proceeds from the issuance of short-term debt. In April 2005 CMP issued $25 million of Series F medium-term notes at 5.78%, due in 2035, to repay the short-term debt. In June 2005 CMP redeemed all $22 million of its 3.50% Series Preferred Stock, $100 par value per share, at a redemption price of $101 per share. In June 2005 CMP issued $20 million of Series F medium-term notes at 5.375%, due in 2035, to finance the 3.50% Series Preferred Stock redemption. In July 2005 CMP issued $25 million of Series F medium-term notes at 5.43%, due in 2035, to fund maturing medium-term notes.

In October 2005 CMP issued $15 million of Series F medium-term notes at 5.70%, due in 2025, and $15 million of Series F medium-term notes at 5.875%, due in 2035, to reduce short-term debt. In November 2005 CMP agreed to issue in January 2006 $30 million of Series F medium-term notes at 5.30%, due in 2016, to refinance maturing debt. In addition to that issuance, in January 2006 CMP issued $10 million of Series F medium-term notes at 5.27%, due in 2016, to refinance maturing debt.

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In September 2005 CNG issued $20 million of Series C medium-term notes at 5.63%, due in 2035, and used the proceeds to reduce short-term debt. In October 2005 CNG issued $25 million of Series C medium-term notes at 5.84%, due in 2035, to fund working capital needs.

In September 2005 SCG paid at maturity $25 million of Series II medium-term notes with proceeds from the issuance of short-term debt. In October 2005 SCG issued $25 million of Series III medium-term notes at 5.78%, due in 2025, to fund working capital needs. In December 2005 SCG issued $20 million of Series III medium-term notes at 5.77%, due in 2035, and $25 million of Series III medium-term notes carrying a floating rate of 7 basis points over 3-month LIBOR, due in June 2007, and callable six months from the date of issuance, to fund working capital needs.

On March 24, 2005, NYSEG filed a Form 15 with the SEC and on June 20, 2005, CMP filed a Form 15 with the SEC, each terminating its status as a registrant under the Securities Exchange Act of 1934 (Exchange Act). NYSEG and CMP will no longer file Exchange Act reports including Forms 10-K, 10-Q and 8-K, and proxy statements or information statements. We do not expect that the termination of either NYSEG's or CMP's Exchange Act registration will materially affect their access to or cost of capital.

In July 2006 Energy East is planning to call, at par, its $345 million, 8 1/4% Capital Securities (mandatorily redeemable trust preferred securities). We expect to write off approximately $11 million of unamortized debt expense when the 8 1/4% Capital Securities are called. In November 2006 Energy East's $232 million 5.75% note matures. Energy East has entered into several arrangements to hedge interest rates in connection with the refinancing of these securities.

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. Both facilities have expiration dates in 2010 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, 2005. Our previous revolving credit agreements, which were replaced in June 2005 by the two facilities described above, provided for consolidated maximum borrowings of $740 million at December 31, 2004.

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 $121 million of such short-term debt outstanding at December 31, 2005, and $206 million outstanding at December 31, 2004. The weighted-average interest rate on short-term debt was 4.6% at December 31, 2005, and 2.8% at December 31, 2004.

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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 $805 million available under the shelf registration statement.

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, 2005, a 1% change in average interest rates would change our annual interest expense for variable-rate debt by about $4 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's and RG&E's current electric rate plans 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. Approximately 45% of NYSEG's, and approximately 75% of RG&E's, total electric load is now provided by an ESCO or at the market price. 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 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, 2006, the portion of load for fixed rate option customers not supplied by owned generation or long-term contracts is 100% hedged for NYSEG, and 100% hedged for RG&E, for on-peak and off-peak periods in 2006. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change earnings less than $150 thousand for NYSEG and less than $100 thousand for RG&E in 2006. 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, 2005, was $153 million, reflecting an increase of $148 million as compared to December 31, 2004. The increase is primarily a result of wholesale market price changes for electricity. Other comprehensive income for 2005 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 rate 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.

Two of our energy marketing subsidiaries 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, 2006, the energy marketing subsidiaries fixed price load was 100% hedged for 2006. 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 and our two energy marketing subsidiaries 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.

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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 $6 million if either our expected return on plan assets or our discount rate were to change by 1/4%. Our accumulated other comprehensive income at December 31, 2005, includes an accumulated loss of $65 million associated with our pension liability. Under RG&E's Electric and Natural Gas Rate Agreements and under NYSEG's natural gas rate plan, changes in pension income resulting from changes in market conditions are deferred. (See Item 8 - Note 14 to our Consolidated Financial Statements and Note 12 to RG&E's Financial Statements.)

Results of Operations

	2005	2004	2003
(Thousands, except per share amounts)			
Operating Revenues	$5,298,543	$4,756,692	$4,514,490
Operating Expenses	$4,605,388	$4,006,739	$3,862,677
Operating Income	$693,155	$749,953	$651,813
Interest Charges, Net and Preferred Stock Dividends of Subsidiaries	$290,371	$280,581	$303,491
Income Taxes on Continuing Operations	$169,997	$251,445	$128,663
Income from Continuing Operations	$256,833	$237,621	$208,490
Net Income	$256,833	$229,337	$210,446
Average Common Shares Outstanding, basic	146,964	146,305	145,535
Earnings per Share from Continuing Operations, basic	$1.75	$1.63	$1.43
Earnings per Share, basic	$1.75	$1.57	$1.45

2005 Earnings per Share

Earnings from continuing operations, basic for 2005 increased 12 cents per share compared to 2004 primarily as a result of:

- An increase of 21 cents per share due to higher margins on electric sales under electric commodity programs for New York customers,
- An increase of 17 cents per share resulting from a 3% increase in electric deliveries, and
- An increase of 4 cents per share 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.

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Those increases were partially offset by:

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

2004 Earnings per Share

Earnings per share from continuing operations, basic for 2004 increased 20 cents compared to 2003 primarily because of:

- Additional earnings of 16 cents per share as a result of one-time and ongoing effects from RG&E's Electric and Natural Gas Rate Agreements, including ratemaking treatment for the sale of Ginna. The one-time effects added 7 cents per share. Ongoing effects added 9 cents per share to earnings, and included increases as a result of RG&E's electric retail access surcharge and natural gas merchant function charge, and annual credits from the ASGA as provided in RG&E's Electric Rate Agreement.
- An increase of 10 cents per share from lower financing costs and savings from integration and efficiency initiatives. Financing costs decreased principally due to redemptions and refinancings of first mortgage bonds and preferred stock of subsidiaries funded, in part, by proceeds from the sale of Ginna, as well as the sale of certain nonutility businesses in 2003 and 2004 and internally generated funds.
- The effect of a loss on retirement of debt that reduced earnings 9 cents per share in 2003.

Those increases were partially offset by:

- Lower income from natural gas operations, due in part to a 2% drop in retail sales, which reduced earnings 7 cents per share.
- A reduction of 6 cents per share due to cumulative stock-based compensation because of changes in the market value of Energy East common stock during 2004.
- A decrease of 3 cents per share because of higher depreciation expense due to electric plant additions, excluding depreciation related to Ginna.

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

Energy East Corporation

Other Items

Pension Income

: Periodic pension income is included in other operating and maintenance expenses and reduces the amount of expense that would otherwise be reported. Other operating and maintenance expenses would have been $1 million higher for 2005 and $20 million lower for 2004 if periodic pension income had not changed compared to the prior year. The changes were primarily due to increased amortization of actuarial gains, partially offset by a reduction in the settlement charge and revised actuarial assumptions including the discount rate used to compute our pension liability (reduced to 5.75% as of December 31, 2004, and to 6.25% (from 6.50%) as of December 31, 2003).

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. We expect pension income to decline in future years as prior year gains are fully amortized. We estimate pension income of $26 million for 2006 and expect to contribute between $10 million and $20 million to our pension plans in 2006. (See Item 8 - Note 14 to our Consolidated Financial Statements.)

	2005	2004	2003
($ in Millions)			
Periodic pension income (pretax)	$30	$29	$49
As a percent of net income	7%	8%	14%

Other (Income) and Other Deductions

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

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 losses on hedge activity related to our electricity contracts and interest rate swap agreements,
- A $3 million decrease in Other deductions for losses from the disposition of nonutility property, and
- A $3 million increase in Other deductions from miscellaneous losses.

The changes for 2004 include:

- An $18 million increase in Other (income), primarily due to higher interest income of $6 million and a $6 million increase as a result of RG&E's Electric Rate Agreement.
- A $13 million decrease in Other deductions primarily due to the effect of a $23 million loss on retirement of debt in 2003.

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

Energy East Corporation

Interest Charges, Net and Preferred Stock Dividends of Subsidiaries

: Interest charges, net and preferred stock dividends of subsidiaries increased a combined $10 million in 2005. The increase is primarily due to:

- A net increase of $115 million in the aggregate amount of long-term debt and preferred stock outstanding, and
- An increase in rates on variable rate debt and notes payable.

Interest charges, net and preferred stock dividends of subsidiaries decreased $23 million in 2004. In July 2003 we began to recognize as interest expense certain distributions that we had previously recognized as preferred stock dividends. The combined decrease is primarily due to:

- Refinancings of long-term debt at lower interest rates, and
- Redemptions and repurchases of first mortgage bonds and preferred stock of subsidiaries.

Income Tax Expense

: The effective tax rate for continuing operations was 40% in 2005, 51% in 2004 and 36% in 2003.

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.

The increase in the 2004 effective tax rate was primarily due to:

- Regulatory treatment of RG&E's deferred gain on the sale of Ginna. RG&E recorded pretax income of $112 million and income tax expense of $112 million. (See Item 8 - Note 2 to our Consolidated Financial Statements.)
- Increases due to changes in estimates of prior year taxes of $3 million.

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

Energy East Corporation

Operating Results for the Electric Delivery Business

	2005	2004	2003
(Thousands)			
Megawatt-hours			
Retail Deliveries	32,019	31,019	30,593
Retail Commodity Sales (1)	14,385	15,613	N/A
Wholesale Sales	9,466	7,855	5,734
Operating Revenues	$2,969,558	$2,781,322	$2,758,695
Electricity purchased and fuel used in generation	$1,457,746	$1,321,081	$1,192,397
Other operating and maintenance expenses	$672,595	$667,503	$767,150
Depreciation and amortization	$178,806	$196,782	$211,120
Operating Expenses	$2,452,506	$2,227,450	$2,311,801
Operating Income	$517,052	$553,872	$446,894

(1)

Included in Retail Deliveries.

Operating Revenues

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

- An increase of $73 million from increases in electric energy supplied by NYSEG and RG&E under commodity options where they provide supply. Higher market prices for electricity more than offset the decline in commodity revenues resulting from more customers electing ESCOs as their electricity supplier.
- 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 $29 million as a result of higher accruals for earnings sharing under NYSEG's and RG&E's electric rate plan provisions.

The $23 million increase in operating revenues for 2004 was primarily the result of:

- Higher wholesale sales of $68 million primarily for NYSEG. The increase reflected higher market prices and increased activity to mitigate supply prices,
- An increase of $5 million due to higher retail deliveries, and
- Certain provisions of RG&E's Electric Rate Agreement that added $10 million to revenues, including $4 million from a retail access surcharge and $6 million as a result of various credits from the ASGA.

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

Energy East Corporation

Those increases were partially offset by:

- A decrease of $27 million due to rate reductions for CMP reflecting lower stranded costs and lower amortization of storm and DSM costs.
- A $19 million decrease due to a change in market structure for RG&E that allows ESCOs to provide electricity, resulting in lower retail revenues partially offset by higher wholesale revenues.
- A $15 million decrease for NYSEG due to reductions in the amount of electricity supplied by NYSEG under its various commodity options.

Operating Expenses

: 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 uncollectibles 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.

The $84 million decrease in operating expenses for 2004 was primarily the result of:

- A net $112 million decrease resulting from the regulatory treatment of RG&E's gain on the sale of Ginna, which includes RG&E's recognition of a $341 million pretax gain partially offset by the after-tax deferral of the gain of $229 million.
- Reduced operating costs of $73 million, including reduced depreciation and decommissioning expenses of $32 million, as a result of the sale of Ginna.
- A $10 million decrease in RG&E's operating and maintenance costs because of certain deferral petitions that were resolved as part of RG&E's Electric Rate Agreement.
- Lower operating costs of $25 million, including $5 million because CMP completed its amortization of storm and DSM costs as of the end of June 2004, $5 million for lower uncollectible expense and a variety of other

sources.

Those decreases were partially offset by:

- Increased purchased power costs of $91 million for RG&E due to the purchases from Ginna beginning in June 2004.
- A $42 million increase due to higher purchased power costs, primarily for increased wholesale sales.
- Higher depreciation of $7 million due to significant additions to plant in service and the accelerated depreciation of legacy accounting systems that were replaced in 2004.

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

Energy East Corporation

Operating Results for the Natural Gas Delivery Business

	2005	2004	2003
(Thousands)			
Deliveries - Dekatherms			
Retail	204,677	208,444	212,745
Wholesale	883	1,593	5,360
Operating Revenues	$1,783,547	$1,549,150	$1,462,127
Operating Expenses	$1,591,037	$1,366,486	$1,263,182
Operating Income	$192,510	$182,664	$198,945

Operating Revenues

: 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.

The $87 million increase in operating revenues for 2004 was primarily as a result of:

- Higher market prices of natural gas of $120 million that were passed on to customers.

That increase was partially offset by:

- Lower retail deliveries of $12 million due to warmer winter weather in the first quarter of 2004, partially offset by higher deliveries in the fourth quarter of 2004.
- Lower transportation revenue and wholesale entitlements of $28 million.

Operating Expenses

: 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.

The $103 million increase in operating expenses for 2004 was primarily the result of:

- Higher natural gas prices of $120 million because of market conditions.

That increase was partially offset by lower natural gas purchases, including:

- Decreases of $6 million due to lower retail deliveries and $16 million due to lower wholesale sales.

Energy East Corporation
Consolidated Statements of Income

Year Ended December 31,	2005	2004	2003
(Thousands, except per share amounts)			
Operating Revenues			
	$4,753,105	$4,330,472	$4,220,822
Utility			
Nonutility	545,438	426,220	293,668
Total Operating Revenues	5,298,543	4,756,692	4,514,490
Operating Expenses			
Electricity purchased and fuel used in generation			
Utility	1,457,746	1,321,081	1,192,397
Nonutility	360,621	249,330	145,972
Natural gas purchased			
Utility	1,161,059	952,806	862,452
Nonutility	107,755	77,508	77,012
Other operating expenses	797,015	799,460	813,133
Maintenance	197,704	173,191	203,043
Depreciation and amortization	277,217	292,457	299,430
Other taxes	246,271	252,860	269,238
Gain on sale of generation assets	-	(340,739)	-
Deferral of asset sale gain	-	228,785	-
Total Operating Expenses	4,605,388	4,006,739	3,862,677
Operating Income	693,155	749,953	651,813
Other (Income)	(32,904)	(35,497)	(17,226)
Other Deductions	8,858	15,803	28,395
Interest Charges, Net	288,897	276,890	284,482
Preferred Stock Dividends of Subsidiaries	1,474	3,691	19,009
Income From Continuing Operations Before Income Taxes	426,830	489,066	337,153
Income Taxes	169,997	251,445	128,663
Income From Continuing Operations	256,833	237,621	208,490
Discontinued Operations			
Loss from discontinued operations (including loss	-	(7,109)	(12,032)
on disposal of $(7,565) in 2004 and $(13,360) in 2003)	-	1,175	(13,988)
Income taxes (benefits)			
(Loss) Income From Discontinued Operations	-	(8,284)	1,956

Net Income	$256,833	$229,337	$210,446
Earnings per Share From Continuing Operations, basic	$1.75	$1.63	$1.43
Earnings per Share From Continuing Operations, diluted	$1.74	$1.62	$1.43
(Loss) Earnings per Share From Discontinued Operations, basic	-	$(.06)	$.02
(Loss) Earnings per Share From Discontinued Operations, diluted	-	$(.06)	$.01
Earnings per Share, basic	$1.75	$1.57	$1.45
Earnings per Share, diluted	$1.74	$1.56	$1.44
Average Common Shares Outstanding, basic	146,964	146,305	145,535
Average Common Shares Outstanding, diluted	147,474	146,713	145,730

The

notes on pages II-56 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31,	2005	2004
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$120,009	$111,465
Investments available for sale	192,925	135,655
Accounts receivable and unbilled revenues, net	933,680	821,556
Fuel and natural gas in storage, at average cost	278,590	198,640
Materials and supplies, at average cost	33,886	27,100
Accumulated deferred income tax benefits, net	-	33,969
Derivative assets	278,855	7,420
Prepayments and other current assets	92,613	86,306
Total Current Assets	1,930,558	1,422,111
Utility Plant, at Original Cost		
Electric	5,403,134	5,282,828
Natural gas	2,574,574	2,493,455
Common	450,641	420,372
	8,428,349	8,196,655
Less accumulated depreciation	2,764,399	2,602,013
Net Utility Plant in Service	5,663,950	5,594,642
Construction work in progress	119,504	67,526
Total Utility Plant	5,783,454	5,662,168
Other Property and Investments, Net	203,159	190,149
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	309,888	356,072
Deferred income taxes	13,482	-
Unfunded future income taxes	117,241	115,446
Environmental remediation costs	135,376	122,052
Unamortized loss on debt reacquisitions	60,933	58,345
Nonutility generator termination agreements	86,890	96,158
Other	384,173	419,214
Total regulatory assets	1,107,983	1,167,287
Other assets		
Goodwill, net	1,525,353	1,525,353

Prepaid pension benefits	741,831	657,402
Derivative assets	69,156	29,472
Other	126,214	142,680
Total other assets	2,462,554	2,354,907
Total Regulatory and Other Assets	3,570,537	3,522,194
Total Assets	$11,487,708	$10,796,622

The

notes on pages II-56 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31,	2005	2004
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$326,527	$59,231
Notes payable	121,347	206,472
Accounts payable and accrued liabilities	629,158	455,384
Interest accrued	46,522	43,469
Taxes accrued	-	8,568
Accumulated deferred income tax, net	80,984	-
Other	188,471	175,896
Total Current Liabilities	1,393,009	949,020
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	797,544	762,520
Deferred income taxes	-	21,487
Gain on sale of generation assets	173,216	233,378
Pension benefits	22,798	25,354
Natural gas hedges	49,205	6,228
Other	124,251	110,034
Total regulatory liabilities	1,167,014	1,159,001
Other liabilities		
Deferred income taxes	1,033,287	973,599
Nuclear plant obligations	234,907	251,753
Other postretirement benefits	428,691	419,885
Environmental remediation costs	166,462	150,263
Other	499,968	417,486
Total other liabilities	2,363,315	2,212,986
Total Regulatory and Other Liabilities	3,530,329	3,371,987
Debt owed to subsidiary holding solely parent debentures	355,670	355,670
Other long-term debt	3,311,395	3,442,015
Total long-term debt	3,667,065	3,797,685
Total Liabilities	8,590,403	8,118,692
Commitments and Contingencies	-	-

Preferred Stock of Subsidiaries		
Redeemable solely at the option of subsidiaries	**24,631**	46,671
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 147,701 shares outstanding at December 31, 2005, and 147,118 shares outstanding at December 31, 2004)	**1,478**	1,472
Capital in excess of par value	1,489,256	1,477,518
Retained earnings	1,294,580	1,201,533
Accumulated other comprehensive income (loss)	89,085	(43,561)
Deferred compensation	-	(5,020)
Treasury stock, at cost (53 shares at December 31, 2005, and 29 shares at December 31, 2004)	**(1,725)**	(683)
Total Common Stock Equity	2,872,674	2,631,259
Total Liabilities and Stockholders' Equity	$11,487,708	$10,796,622

The

notes on pages II-56 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Cash Flows

Year Ended December 31,	2005	2004	2003
(Thousands)			
Operating Activities			
Net income	$256,833	$229,337	$210,446
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	382,873	377,181	419,237
Income taxes and investment tax credits deferred, net	69,729	83,327	103,236
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	(29,967)	(28,808)	(40,128)
Changes in current operating assets and liabilities			
Accounts receivable, net	(107,308)	(70,067)	(56,188)
Inventory	(86,735)	(43,579)	(50,775)
Prepayments and other current assets	(36,373)	1,326	8,732
Accounts payable and accrued liabilities	198,932	91,527	(9,999)
Taxes accrued	1,376	(91,840)	(15,315)
Customer refund	(25,329)	(58,219)	-
Other current liabilities	11,448	(37,213)	15,941
Pension contributions	(54,320)	(19,661)	(20,006)
Other assets	(76,292)	(82,874)	(114,466)
Other liabilities	(4,595)	(11,337)	25,052
Net Cash Provided by Operating Activities	500,272	339,100	475,767
Investing Activities			
Sale of generation assets	-	453,678	-
Excess decommissioning funds retained	-	76,593	-
Utility plant additions	(331,294)	(299,263)	(289,320)
Other property and investments additions	(2,507)	(5,623)	(39,060)
Other property and investments sold	25,704	6,161	72,478
Maturities of current investments available for sale	1,635,005	994,680	-
Purchases of current investments available for sale	(1,692,275)	(1,130,335)	-
Other	(3,064)	1,062	(6,678)
Net Cash (Used in) Provided by Investing Activities	(368,431)	96,953	(262,580)
Financing Activities			
Issuance of common stock	2,654	3,083	4,234

Repurchase of common stock	(6,492)	(6,071)	-
Issuance of first mortgage bonds	70,000	-	-
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	(47,260)	(201,005)	(242,066)
Long-term note issuances	208,893	212,975	504,769
Long-term note repayments	(120,061)	(249,025)	(488,654)
Notes payable three months or less, net	(85,124)	(92,932)	(7,044)
Notes payable issuances	-	4,000	11,000
Notes payable repayments	-	(13,000)	(17,750)
Book overdraft	4,460	5,892	-
Dividends on common stock	(150,367)	(136,374)	(127,940)
Net Cash Used in Financing Activities	(123,297)	(472,457)	(363,451)
Net Increase (Decrease) in Cash and Cash Equivalents	8,544	(36,404)	(150,264)
Cash and Cash Equivalents, Beginning of Year	111,465	147,869	298,133
Cash and Cash Equivalents, End of Year	$120,009	$111,465	$147,869

The

notes on pages II-56 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Treasury Stock	Total
Balance, January 1, 2003	144,966	$1,455	$1,444,941	$1,061,428	$(34,167)	-	$(15,768)	$2,457,889
Net income				210,446				210,446
Other comprehensive income, net of tax					22,953			22,953
Comprehensive income								233,399
Amortization of excess capital over par			141					141
Common stock dividends declared ($1.00 per share)				(145,417)				(145,417)
Common stock issued - Investor Services Program	1,064	8	21,703					21,711
Common stock issued - restricted stock plan	229		(1,893)			$(4,401)	6,294	-
Amortization of deferred compensation under restricted stock plan						1,581		1,581
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	3		(9,046)				9,110	64
Amortization of capital stock issue expense			385					385
Balance, December 31,	146,262	1,463	1,456,220	1,126,457	(11,214)	(2,820)	(364)	2,569,742

2003

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
Common stock repurchased	(250)						(6,071)	(6,071)
Common stock issued - restricted stock plan	242		(132)			(5,784)	5,916	-
Amortization of deferred compensation under restricted stock plan						3,584		3,584
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	(8)		94				(164)	(70)
Amortization of capital stock issue expense			385					385
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				(163,786)				(163,786)

share)								
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
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	(39)		1,702				(1,405)	297
Amortization of capital stock issue expense			385					385
Balance, December 31, 2005	147,701	$1,478	$1,489,256	$1,294,580	$89,085	-	$(1,725)	$2,872,674

The

notes on pages II-56 through II-83 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 and corporate offices in New York and Maine. Our wholly-owned subsidiaries, and their principal operating utilities, are: Berkshire Energy - Berkshire Gas; CMP Group - CMP; CNE - SCG; CTG Resources - CNG; and RGS Energy - NYSEG and RG&E.

Accounts receivable

: Accounts receivable include unbilled revenues of $315 million at December 31, 2005, and $227 million at December 31, 2004, and are shown net of an allowance for doubtful accounts of $53 million at December 31, 2005, and $45 million at December 31, 2004. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $63 million in 2005, $45 million in 2004 and $48 million in 2003.

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. During the third quarter of 2005 we re-examined the set of estimates used for all the operating companies and determined that some operating companies required changes to the assumptions used in determining their unbilled revenue estimates.

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.

Notes to Consolidated Financial Statements

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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.

In March 2005 the FASB issued FIN 47, which 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. For calendar-year enterprises such as Energy East and its subsidiaries, FIN 47 was effective no later than December 31, 2005. 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 was $30 million at December 31, 2005, and includes our estimated conditional asset retirement obligation of $28 million. It primarily consists of obligations related to removal or retirement of: asbestos, polychlorinated biphenyl (PCB) contaminated equipment, gas pipeline and cast iron gas mains. Our asset retirement obligation was $2 million at December 31, 2004, and primarily consisted of obligations related to cast iron gas mains. The table below presents the various amounts related to our asset retirement obligation as of December 31, 2005. Changes in the assumptions underlying the items shown could affect the balance sheet amounts and future costs related to the obligations.

As of December 31,	2005
(Thousands)	
Asset retirement obligation	$(29,895)
Regulatory asset	$9,570
Regulatory liability	$(7,656)
Increase in utility plant	$5,092
Decrease in accumulated depreciation	$22,889

Our pro forma conditional asset retirement obligation was $27 million at December 31, 2004, and $25 million at January 1, 2004.

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.

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

Year Ended December 31,	2005	2004	2003
(Thousands)			
Basic average common shares outstanding	146,964	146,305	145,535
Restricted stock awards	510	408	195
Potentially dilutive common shares	343	313	197
Options issued with SARs	(343)	(313)	(197)
Dilutive average common shares outstanding	147,474	146,713	145,730

Options that have an exercise price that is greater than the average market price of the common shares during the year are excluded from the determination of EPS. Shares excluded from the EPS calculation were: 0.4 million in 2005, 2.0 million in 2004 and 2.9 million in 2003. (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	2005	2004	2003
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	$247,434	$245,992	$245,223
Income taxes, net of benefits received	$102,647	$140,823	$(12,879)

The amount of capitalized interest was $1 million in 2005 and 2004 and $4 million in 2003.

Decommissioning expense:

Other operating expenses for 2004 and 2003 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. (See Note 10 for information about decommissioning expenses incurred by companies that are partially owned by CMP.)

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 - 53 years, distribution property - 48 years, generation property - 44 years, gas production property - 33 years, gas storage property - 25 years, and other property - 34 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 2 years for its coal station to 29 years for its hydroelectric stations. Our depreciation accruals were equivalent to 3.3% of average depreciable property for 2005 and 2004 and 3.4% for 2003.

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

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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.

Goodwill

: The excess of the cost over fair value of net assets of purchased businesses is recorded 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.)

Income 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. ITCs are amortized over the estimated lives of the related assets.

Other (Income) and Other Deductions:

Year Ended December 31,	2005	2004	2003
(Thousands)			
Interest and dividend income	$(15,802)	$(12,421)	$(6,457)
Allowance for funds used during construction	(1,552)	(582)	(1,965)
Gains from hedge activity	(2,701)	(4,544)	-
2004 RG&E Electric and Natural Gas Rate Agreement	-	(6,117)	-
Earnings from equity investments	(3,959)	(3,930)	(4,702)
Miscellaneous	(8,890)	(7,903)	(4,102)
Total other (income)	$(32,904)	$(35,497)	$(17,226)
Retirement of debt	-	$781	$22,784

Losses from disposition of nonutility property	$100	3,543	487
Losses from hedge activity	40	5,727	-
Donations, civic and political	3,744	1,665	75
Merger-enabled gas supply savings	796	4,651	-
Miscellaneous	4,178	(564)	5,049
Total other deductions	$8,858	$15,803	$28,395

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.

Reclassifications

: Certain amounts have been reclassified in our consolidated financial statements to conform to the 2005 presentation.

Notes to Consolidated Financial Statements

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We revised the presentation of our investments in auction rate securities, classifying them as current investments available-for-sale rather than as cash and cash equivalents. We held current investments of $193 million at December 31, 2005, and $136 million at December 31, 2004, 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.

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. They 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, DSM 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.

Other regulatory assets consist primarily of deferred natural gas costs of $78 million, the deferred loss on the sale of RG&E's Oswego generating unit of $48 million that is being recovered through June 2013, RG&E's 2003 deferred ice storm costs of $32 million that are being recovered through April 2014 and deferred costs of $24 million for RG&E's merger with Energy East that are being recovered through December 2007. Other regulatory liabilities consist primarily of accrued earnings sharing amounts of $48 million that will be added to NYSEG's and RG&E's respective ASGAs and ultimately returned to customers.

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 New England, the New England Power Pool, or any other independent system operator or similar entity. All of CMP's power entitlements under its NUG and other purchase power contracts are sold 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.

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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.

NYSEG, RG&E and our two energy marketing subsidiaries 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.

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As of December 31, 2005, the maximum length of time over which we had hedged our exposure to the variability in future cash flows for forecasted energy transactions was 48 months. We estimate that gains of $230 million will be reclassified from accumulated other comprehensive income into earnings in 2006, 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)

: In December 2004 the FASB issued Statement 123(R), which is a revision of Statement 123. Statement 123(R) 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. As amended by the SEC, a public company is required to prepare financial statements in accordance with Statement 123(R) beginning with the first annual reporting period of its first fiscal year beginning on or after June 15, 2005. The FASB encouraged early adoption.

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. As of October 1, 2005, our application of Statement 123(R) had the following effects: reduced income from continuing operations before income taxes $3.4 million, reduced income from continuing operations and net income $2.0 million and reduced basic and diluted EPS one cent. 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 additional paid-in capital 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.

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. Prior to our adoption of Statement 123(R), we applied APB 25, as permitted by Statement 123, to account for our stock-based compensation to employees. We also incurred a liability for our stock option plan awards under ABP 25, but we used the intrinsic value method to determine our liability and the related compensation cost. 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 under APB 25 for such awards.

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During the second quarter of 2005 the SEC staff provided its views concerning vesting of stock-based awards based on retirement eligibility criteria. We previously applied APB 25 and followed the nominal vesting period approach for our restricted stock awards, which have a retirement eligibility provision. Following the nominal vesting period approach, we record compensation expense over the estimated vesting period for the restricted stock award, 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.

Upon adoption of Statement 123(R) we now follow the nonsubstantive vesting period approach for any new awards of restricted stock. According to that approach, an award is considered to be vested for expense recognition purposes when the employee's retention of the award is no longer contingent on providing subsequent service. Therefore, the compensation cost will be recognized immediately for restricted stock granted to an employee who is eligible for retirement on the date of the grant. We will continue to follow the nominal vesting period approach for any restricted stock awards granted prior to our adoption of Statement 123(R), including the remaining portion of nonvested outstanding awards. The pro forma compensation cost for 2005, 2004 and 2003 following the nonsubstantive vesting period approach is not materially different from the compensation cost recognized following the nominal vesting period approach.

Statement 150

: In May 2003 the FASB issued Statement 150, which requires that certain financial instruments be classified as liabilities in statements of financial position. Under previous guidance such instruments could be classified as equity. We adopted Statement 150 as of July 1, 2003, and classified as a liability, rather than as equity, RG&E's $25 million of mandatorily redeemable preferred stock (which RG&E redeemed in 2004). We also began to recognize as interest expense distributions that we had previously recognized as preferred stock dividends. The adoption of Statement 150 did not have a material effect on our financial position, results of operations or cash flows.

Variable interest entities

: In December 2003 the FASB issued FIN 46(R), which 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.

Two of our operating utilities have independent, ongoing, power purchase contracts with NUGs. However, they were not involved in the formation of and do not have ownership interests in any NUGs. We have evaluated all of the 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. We are not able to apply FIN 46(R) to seven NUGs because we are unable to obtain the information necessary to: (1) determine if any of the seven NUGs is a variable interest entity,

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(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 seven 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, 2005 or 2004.

The two operating utilities purchase electricity from the seven NUGs at above-market prices. We are not exposed to any loss as a result of either of the two companies' involvement with the NUGs because they are allowed to recover through rates the cost of their purchases. Also, they are under no obligation to a NUG if it decides not to operate for any reason. The combined contractual capacity for the seven NUGs is approximately 517 MWs. The combined purchases from the seven NUGs totaled approximately $376 million in 2005, $325 million in 2004 and $346 million in 2003.

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 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 owns 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 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.

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In 2003 Berkshire Propane, Inc., a subsidiary of Berkshire Energy, sold its assets and Energetix, a subsidiary of RGS Energy, sold its subsidiary Griffith Oil Co., Inc. In 2004 we recorded a change in estimated 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.

The results of discontinued operations of the businesses sold were:

Year Ended December 31,	2004	2003
(Thousands)		
Component of Energy East Solutions, Inc.		
Revenues	$48,634	$57,478
(Loss) income from operations of discontinued business	$(859)	$68
Income taxes (benefits)	(142)	27
(Loss) income from discontinued operations	$(717)	$41
Certain Divisions of Union Water Power Company		
Revenues	$13,156	$21,851
Loss from operations of discontinued business	$(6,250)	$(2,147)
Income taxes (benefits)	151	(1,003)
Loss from discontinued operations	$(6,401)	$(1,144)
Griffith Oil Co., Inc.		
Revenues	-	$321,447
Loss from operations of discontinued business	-	$(7,798)
Income taxes (benefits)	$1,166	(13,387)
(Loss) income from discontinued operations	$(1,166)	$5,589
Berkshire Propane, Inc.		
Revenues	-	$5,494
Loss from operations of discontinued business	-	$(2,155)
Income taxes	-	375
Loss from discontinued operations	-	$(2,530)
Totals for discontinued operations		
Total revenues	$61,790	$406,270
Total loss from operations of discontinued businesses	$(7,109)	$(12,032)
Total income taxes (benefits)	1,175	(13,988)

Total (loss) income from discontinued operations	$(8,284)	$1,956

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 and determined that we had no impairment of goodwill or unamortized intangible assets at September 30, 2005.

The carrying amount of goodwill at December 31, 2005, was the same as at December 31, 2004. The amounts of goodwill by operating segment (in thousands) are:

Electric Delivery	Natural Gas Delivery	Other	Total
$844,491	$676,588	$4,274	$1,525,353

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Other Intangible Assets:

Our unamortized intangible assets had a carrying amount of $19 million at December 31, 2005, and $10 million at December 31, 2004, and primarily consisted of pension assets. Our amortized intangible assets had a gross carrying amount of $31 million at December 31, 2005 and 2004, and primarily consisted of investments in pipelines and customer lists. Accumulated amortization was $18 million at December 31, 2005, and $15 million at December 31, 2004. Estimated amortization expense for intangible assets is approximately $1 million for each of the next five years, 2006 through 2010.

Note 5. Income Taxes

Year Ended December 31,	2005	2004	2003
(Thousands)			
Current			
Federal	$87,058	$99,268	$19,920
State	14,800	19,186	392
Current taxes charged to expense	101,858	118,454	20,312
Deferred			
Federal	55,821	123,517	92,945
State	15,438	17,545	19,057
Deferred taxes charged to expense	71,259	141,062	112,002
ITC adjustments	(3,120)	(8,071)	(3,651)
Total for Continuing Operations	$169,997	$251,445	$128,663

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

Year Ended December 31,	2005	2004	2003
(Thousands)			
Tax expense at statutory rate	$149,907	$172,465	$124,656
Depreciation and amortization not normalized	11,859	2,220	10,715
ITC amortization	(3,120)	(8,071)	(3,651)
Trust preferred securities	-	-	(4,978)
ASGA, Ginna	-	80,075	-
State taxes, net of federal benefit	19,654	23,875	12,641
Other, net	(8,303)	(19,119)	(10,720)
Total for Continuing Operations	$169,997	$251,445	$128,663

The effective tax rate for continuing operations was 40% in 2005, 51% in 2004 and 36% in 2003. 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.)

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At December 31, 2005 and 2004, our consolidated deferred tax assets and liabilities consisted of:

	2005	2004
(Thousands)		
Current Deferred Income Tax Assets (Liabilities)		
Derivative assets	$(110,390)	-
	29,406	$33,969
Other		
Total Current Deferred Income Tax Assets (Liabilities)	$(80,984)	$33,969
Noncurrent Deferred Income Tax Liabilities		
Depreciation	$946,155	$869,919
Unfunded future income taxes	136,059	148,116
Accumulated deferred ITC	38,604	41,723
Deferred (gain) loss on sale of generation assets	(49,715)	(65,485)
Pension	170,541	146,756
Statement 106 postretirement benefits	(135,205)	(121,292)
Derivative (liabilities) assets	(11,132)	4,204
Other	(75,502)	(28,855)
Total Noncurrent Deferred Income Tax Liabilities	1,019,805	995,086
Less amounts classified as regulatory liabilities		
Deferred income taxes	(13,482)	21,487
Noncurrent Deferred Income Tax Liabilities	$1,033,287	$973,599

Energy East and its subsidiaries have no federal tax credit or loss carryforwards and no valuation allowances.

Note 6. Long-term Debt

Debt owed to subsidiary holding solely parent debentures:

The debt owed to a subsidiary holding solely parent debentures consists of Energy East's 8 1/4% junior subordinated debt securities maturing on July 1, 2031, that are held by Energy East Capital Trust I.

Energy East Capital Trust I is a Delaware business trust that is a wholly-owned finance subsidiary of Energy East. Based on the trust's structure we are not considered the primary beneficiary of the trust and do not consolidate the trust. The assets of the trust consist of our 8 1/4% junior subordinated debt securities. The trust has issued $345 million of mandatorily redeemable trust preferred securities that are 8 1/4% Capital Securities. We have fully and unconditionally guaranteed the trust's payment obligations with respect to the Capital Securities. In July 2006 Energy East is planning to call, at par, its $345 million, 8 1/4% Capital Securities. We expect to write off approximately $11 million of unamortized debt expense when the 8 1/4% Capital Securities are called.

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Other long-term debt:

At December 31, 2005 and 2004, our consolidated other long-term debt was:

				Amount (Thousands)	
Company		Interest Rates	Maturity	2005	2004
	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	3.00% - 3.395%	2032	60,500	60,500
SCG	Medium Term Note I, II & III	4.57% - 7.95%	2006 - 2035	224,000	179,000
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				830,500	785,500
	Pollution control notes, fixed				
NYSEG	1994 Series A & E	5.90% - 6.00%	2006	37,000	37,000
NYSEG	1985 Series A, B & D	4.00% - 4.10%	2015	132,000	72,000
NYSEG	1987 Series A	6.15%	2026	-	65,000
NYSEG	2004 Series C	3.245%	2034	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 pollution control notes, fixed				314,000	219,000
	Pollution control notes, variable				
NYSEG	1985 Series A	1.08%	2015	-	60,000
NYSEG	2005 Series A	3.55%	2026	65,000	-
NYSEG	2004 Series A, B & C	3.40% - 3.51%	2027 - 2034	104,000	204,000

NYSEG	1994 Series B, C, D1 & D2	3.05% - 3.19%	2029	175,000	175,000
RG&E	1997 Series A, B & C	2.90% - 3.10%	2032	101,900	101,900
TEN Cos	Industrial Revenue Variable Rate Demand Bonds	3.59%	2025 - 2030	14,900	14,900
Total pollution control notes, variable				460,800	555,800
	Various long-term debt				
Energy East	Unsecured Note	5.75%	2006	232,350	232,850
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
NYSEG	Unsecured Notes	4.375% - 5.75%	2007 - 2023	450,000	450,000
CMP	Series E & F Medium Term Notes	4.25% - 8.125%	2006 - 2035	310,700	255,700
CNG	Medium Term Notes Series A , B & C	5.63% - 9.10%	2007 - 2035	149,000	104,000
Berkshire Gas	Unsecured Notes	4.76% - 9.60%	2011 - 2021	36,000	36,000
Energetix	Promissory Note	8.50%	2006	3,509	5,657
TEN Cos	Senior Secured Term Notes	6.90% - 6.99%	2009 - 2010	35,000	40,000
NORVARCO	Promissory and Senior Note	7.05% - 10.48%	2020	17,556	18,739
Total various long-term debt				2,034,115	1,942,946
Obligations under capital leases				26,855	29,268
Unamortized premium and discount on debt, net				(28,348)	(31,268)
				3,637,922	3,501,246
Less debt due within one year, included in current liabilities				326,527	59,231
Total				$3,311,395	$3,442,015

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

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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, 2005, other long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years is:

2006	2007	2008	2009	2010
$326,527	$257,236	$96,326	$148,924	$261,339

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 2010 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, 2005. At December 31, 2004, Energy East and its subsidiaries had revolving credit agreements with various expiration dates in 2005 and 2009 that provided for consolidated maximum borrowings of $740 million. Energy East pays a facility fee of 12.5 basis points annually on its $300 million revolver and each joint borrower pays a facility fee on its revolver sublimit, ranging from 8 to 12.5 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 $121 million of such short-term debt outstanding at December 31, 2005, and $206 million outstanding at December 31, 2004. The weighted-average interest rate on short-term debt was 4.6% at December 31, 2005, and 2.8% at December 31, 2004.

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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. 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 0.54 to 1.00 at December 31, 2005. 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. 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, 2005 and 2004, our consolidated preferred stock was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding(1)	Amount (Thousands)	
				2005	2004
CMP, 6% Noncallable	$100	-	5,180	$518	$518
CMP, 3.50%	100	$101.00	-	-	22,000
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	2,044	204	244
CNG, 6.00%	100	110.00	4,104	411	411
CNG, 8.00% Noncallable	3.125	-	108,706	339	339
Total			1	$24,631	$46,671

(1)

At December 31, 2005, Energy East and its subsidiaries had 16,731,356 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.

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Our subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2003 through 2005:

Subsidiary	Date	Series	Amount
			(Thousands)
CNG	September 16, 2003	8.00%	$0.4
Berkshire Gas	September 9, 2003	4.80%	$7.5
Berkshire Gas	September 16, 2004	4.80%	$5.6
Berkshire Gas	September 15, 2005	4.80%	$39.9
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 amounts in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. Capital spending in 2006 is expected to be paid for principally with internally generated funds. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates, and the RG&E transmission project.

Nonutility generator power purchase contracts

: We expensed approximately $631 million for NUG power in 2005, $613 million in 2004 and $608 million in 2003. We estimate that our NUG power purchases will be $571 million in 2006, $575 million in 2007, $410 million in 2008, $244 million in 2009 and $83 million in 2010.

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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 $263 million for nuclear entitlement power in 2005, $199 million in 2004 and $106 million in 2003. We estimate that our nuclear entitlement power purchases will be $260 million in 2006, $303 million in 2007, $286 million in 2008, $289 million in 2009, and $306 million in 2010.

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.

The FERC issued an order directing the NYISO to modify certain energy prices for May 8 and 9, 2000, and to back bill NYISO market participants, including NYSEG and RG&E. The NYISO and many market participants filed requests for rehearing with the FERC concerning that order. While the FERC has not ruled on those requests for rehearing, on July 8, 2005, and October 7, 2005, the NYISO issued back billings that reflected the FERC order concerning the May 2000 issues. NYSEG's updated back billing relating to May 8 and 9, 2000, was approximately $2 million and RG&E's was approximately $1 million. In the third quarter of 2005 NYSEG and RG&E deferred the amounts associated with the back billings as regulatory mandates, pursuant to their Electric Rate Agreements approved by the NYPSC.

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, four 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 $2 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

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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 59 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 three of those four sites are 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 46 of the 59 sites.

Our estimate for all costs related to investigation and remediation of the 59 sites ranges from $161 million to $296 million at December 31, 2005. 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 $161 million at December 31, 2005, and $140 million at December 31, 2004. 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 accounted for as reductions to their related regulatory assets.

Nuclear decommissioning

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

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Each of the three nuclear generating 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.

	Maine Yankee	Yankee Atomic	Connecticut Yankee
($ in Millions)			
Ownership share	38%	9.5%	6%
2005 decommissioning and spent fuel storage costs	$20.9	$5.2	$6.9
Share of remaining decommissioning and other costs (in 2005 dollars)	$85.9	$12.8	$27.6
Equity interest at December 31, 2005	$10.5	-	$2.7

Maine Yankee's decommissioning was completed in 2005. Yankee Atomic's decommissioning is scheduled to be completed during 2006 and Connecticut Yankee's decommissioning is scheduled to be completed during 2007. Yankee Atomic increased its decommissioning and spent fuel storage costs in January 2006. 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 Connecticut Yankee decommissioning costs in March 2005 and will begin to collect the higher Yankee Atomic decommissioning costs 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,	2005		2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
Noncurrent investments - classified as available-for-sale	$88,432	$88,432	$67,310	$67,310
Debt owed to affiliate	$355,670	$358,817	$355,670	$379,571
First mortgage bonds	$829,551	$922,079	$784,065	$896,747
Pollution control notes, fixed	$314,000	$322,510	$219,000	$229,280
Pollution control notes, variable	$460,800	$460,800	$555,800	$555,800
Various long-term debt	$2,006,716	$2,150,762	$1,913,113	$2,110,980

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.

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Note 12. Share-Based Compensation

As of December 31, 2005, we have two share-based compensation plans, which are described below. The total compensation cost charged against income for those plans for the years ended December 31 was: $4.5 million for 2005, $21.1 million for 2004 and $4.5 million for 2003. The total income tax benefit recognized in the income statement for share-based compensation arrangements for the years ended December 31 was: $1.8 million for 2005, $8.4 million for 2004 and $1.8 million for 2003.

Stock options/SARs:

Under our 2000 Stock Option Plan (the Plan), which is shareholder approved, 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 described below. In accordance with Statement 123(R), we will measure the fair value of the stock options/SARs on the date of grant, when we will begin to recognize compensation cost, and remeasure the fair value at the end of each reporting period. 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. At the end of 2005 the expected volatility was 13.93% and the expected dividend yield was 4.46%. 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 and ranges from less than one year to five years. 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.

We applied APB Opinion No. 25, as permitted by Statement 123, to account for our stock-based compensation prior to October 1, 2005. Stock options/SARs were accounted for as liability instruments and related compensation was determined using the intrinsic value method during the nine months ended September 30, 2005, and the years 2004 and 2003.

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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, 2005.

	Stock Options/ SARs	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (Thousands)
Outstanding at January 1, 2005	4,356,682	$22.72		
Options/SARs granted	737,029	$24.62		
SARs exercised	(1,895,554)	$21.60		
Options/SARs forfeited or expired	(38,169)	$25.33		
Outstanding at December 31, 2005	3,159,988	$23.81	6.8	$1,965
Exercisable at December 31, 2005	2,196,332	$23.38	6.0	$1,965

The weighted-average grant-date fair value of stock options/SARs granted during the years ended December 31 was: $2.82 for 2005, $2.93 for 2004 and $3.01 for 2003. The total intrinsic value of share-based liabilities paid during the years ended December 31 was: $10.5 million for 2005, $13.4 million for 2004 and $2.7 million for 2003.

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: $26.42 for 2005, $23.90 for 2004 and $19.20 for 2003.

The following table provides a summary of restricted stock activity and other information for the year ended December 31, 2005:

Restricted Stock Plan	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2005	418,168	$21.71
Granted	265,406	$26.42
Vested	(106,115)	$19.47
Forfeited	(1,181)	$26.12
Nonvested at December 31, 2005	576,278	$24.29

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As of December 31, 2005, there was $6.3 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 two years. The total fair value of shares vested during the years ended December 31 was: $2.1 million for 2005, $0.7 million for 2004 and $0.3 million for 2003.

Note 13. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2003	2003 Change	Balance December 31, 2003	2004 Change	Balance December 31, 2004	2005 Change	Balance December 31, 2005
(Thousands)							
Unrealized gains (losses) on investments:							
Unrealized holding gains during period, net of income tax (expense) of $(253) for 2003, $(316) for 2004 and $(210) for 2005		$395		$491		$333	
Net unrealized (losses) gains on investments	$(1,291)	395	$(896)	491	$(405)	333	$(72)
Minimum pension liability adjustment, net of income tax benefit (expense) of $(14,484) for 2003, $8,114 for 2004 and $8,674 for 2005	(61,661)	21,541	(40,120)	(7,915)	(48,035)	(16,983)	(65,018)
Unrealized gains (losses) on derivatives qualified as hedges:							
Unrealized gains during period on derivatives							

qualified as hedges, net of		22,320		8,964		167,352	
income tax (expense) of $(14,391) for 2003, $(5,061) for 2004 and $(107,041) for		(21,303)		(33,887)		(18,056)	
2005 Reclassification adjustment for (gains) included in net income, net of income tax expense of $14,123 for 2003, $22,037 for 2004 and $11,987 for 2005							
Net unrealized gains (losses) on derivatives qualified as hedges	28,785	1,017	29,802	(24,923)	4,879	149,296	154,175
Accumulated Other Comprehensive Income (Loss)	$(34,167)	$22,953	$(11,214)	$(32,347)	$(43,561)	$132,646	$89,085

(See Risk management in Note 1.)

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Note 14. Retirement Benefits

Energy East sponsors defined benefit pension plans and postretirement benefit plans applicable to substantially all employees. We use a December 31 measurement date for our pension and postretirement benefit plans.

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$2,254,209	$2,140,119	$559,977	$611,236
Service cost	35,379	32,069	5,775	6,082
Interest cost	127,785	130,891	30,719	34,672
Plan participants' contributions	-	-	642	-
Plan amendments	418	6,536	-	(13,361)
Actuarial loss (gain)	81,844	145,100	(23,686)	(37,532)
Divestitures	-	(54,444)	-	(6,071)
Benefits paid	(132,887)	(146,062)	(36,430)	(35,049)
Benefit obligation at December 31	$2,366,748	$2,254,209	$536,997	$559,977
Change in plan assets				
Fair value of plan assets at January 1	$2,475,494	$2,392,066	$32,105	$37,019
Actual return on plan assets	187,449	260,652	1,516	3,047
Employer contributions	54,469	19,661	26,463	26,617
Divestitures	-	(50,823)	-	-
Plan participants' contributions	-	-	642	-
Benefits paid	(132,887)	(146,062)	(29,598)	(34,578)
Fair value of plan assets at December 31	$2,584,525	$2,475,494	$31,128	$32,105
Funded status	$217,777	$221,285	$(505,869)	$(527,872)
Unrecognized net actuarial loss	481,244	388,724	66,349	97,932
Unrecognized prior service cost (benefit)	42,810	47,393	(36,770)	(44,372)
Unrecognized net transition obligation	-	-	47,599	54,427
Prepaid (accrued) benefit cost	$741,831	$657,402	$(428,691)	$(419,885)
Amounts recognized on the balance sheet				
Prepaid benefit cost	$741,831	$657,402	-	-

Accrued benefit cost	-	-	$(428,691)	$(419,885)
Additional minimum liability	(185,791)	(166,418)	-	-
Intangible asset	6,595	7,016	-	-
Regulatory liability	76,914	76,914	-	-
Accumulated other comprehensive income	102,282	82,488	-	-
Net amount recognized	$741,831	$657,402	$(428,691)	$(419,885)

Our accumulated benefit obligation for all defined benefit pension plans was $2.2 billion at December 31, 2005, and $2.0 billion at December 31, 2004. The sale of Ginna in 2004 resulted in a decrease of $54 million in the projected benefit obligation, and $51 million of pension funds were transferred as part of the sale.

CMP's, CNG's and SCG's postretirement benefits were partially funded as of December 31, 2005 and 2004.

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The minimum liability included in other comprehensive income for pension benefits increased $20 million in 2005 and $16 million in 2004. 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 is prescribed when the accumulated benefit obligation in the plan exceeds 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.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.50%	5.75%	5.50%	5.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

As of December 31, 2005, we decreased our discount rate from 5.75% to 5.50%. 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.

	Pension Benefits			Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
(Thousands)						
Components of net periodic benefit cost						
Service cost	$35,379	$32,069	$31,216	$5,775	$6,082	$6,686
Interest cost	127,785	130,891	132,491	30,719	34,672	36,712
Expected return on plan assets	(214,012)	(206,120)	(204,173)	(2,248)	(2,480)	(2,801)
Amortization of prior service cost	4,994	4,650	4,985	(7,577)	(7,273)	(6,879)
Recognized net actuarial loss (gain)	15,887	(1,106)	(6,185)	8,630	4,968	6,729
Amortization of transition (asset) obligation	-	(1,230)	(7,238)	6,800	8,001	8,066
Curtailment	-	(148)	403	-	230	(614)
Settlement charge	-	12,186	-	-	(6,131)	-
Net periodic benefit cost	$(29,967)	$(28,808)	$(48,501)	$42,099	$38,069	$47,899

Net periodic benefit cost is included in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount charged to expense for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred was $59 million as of December 31, 2005, and $67 million as of December 31, 2004. We expect to recover any deferred postretirement costs by 2012. We are amortizing the transition obligation for postretirement benefits that resulted from the adoption of Statement 106 over 20 years.

Notes to Consolidated Financial Statements

Energy East Corporation

Weighted-average assumptions used to determine net periodic benefit cost	Pension Benefits			Postretirement Benefits		
Year ended December 31,	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	6.25%	6.50%	5.75%	6.25%	6.50%
Expected return on plan assets	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%

Our expected rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes. That analysis also considered both current capital market conditions and projected future 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.

We assumed a 10.0% annual rate of increase in the per capita cost of covered health care benefits for 2006 that gradually decreases to 5.0% by the year 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 components	$1,944	$(1,714)
Effect on postretirement benefit obligation	$26,282	$(22,531)

Our weighted-average asset allocations at December 31, 2005 and 2004, by asset category, are:

	Pension Benefits			Postretirement Benefits		
Asset Category	Target Allocation	2005	2004	Target Allocation	2005	2004
Equity securities	60%	64%	62%	50%	56%	54%
Debt securities	30%	28%	32%	45%	37%	40%
Real estate	5%	2%	-	-	-	-
Other	5%	6%	6%	5%	7%	6%
Total	100%	100%	100%	100%	100%	100%

Our 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 our risk tolerance. This is achieved through the utilization of multiple asset managers and systematic allocation to investment management styles, providing a broad exposure to different segments of the fixed income and equity markets.

Notes to Consolidated Financial Statements

Energy East Corporation

Our postretirement benefits plan assets are held with various trustees in multiple VEBA and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved through the utilization of multiple institutional mutual and money market funds, which provide exposure to different segments of the fixed income, equity and short-term cash markets.

Equity securities did not include any Energy East common stock as of December 31, 2005 and 2004.

As of December 31, 2005 and 2004, the accumulated benefit obligation and the projected benefit obligation exceeded the fair value of pension plan assets for CMP's, CNG's and SCG's plans. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those three companies' plans.

	Benefit Obligation Exceeds Fair Value of Plan Assets	
December 31,	2005	2004
(Thousands)		
Projected benefit obligation	$569,560	$529,433
Accumulated benefit obligation	$511,653	$474,250
Fair value of plan assets	$456,593	$397,714

Our funding policy is to make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute between $10 million and $20 million to our pension plans and approximately $10 million to our other postretirement benefit plans in 2006.

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 as follows:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2006	$129,872	$47,714	$3,212
2007	$133,671	$50,905	$3,569
2008	$139,097	$54,254	$4,020
2009	$146,110	$57,711	$4,423
2010	$153,376	$61,209	$4,781
2011 - 2015	$865,901	$344,778	$28,782

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, and interest income, intersegment eliminations and our other nonutility businesses.

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
2005				
Operating Revenues	$2,969,558	$1,783,547	$545,438	$5,298,543
Depreciation and Amortization	$178,806	$85,049	$13,362	$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
2003				
Operating Revenues	$2,758,695	$1,462,127	$293,668	$4,514,490
Depreciation and Amortization	$211,120	$81,433	$6,877	$299,430
Interest Charges, Net	$201,684	$76,113	$6,685	$284,482
Income Taxes (Benefits)	$89,337	$50,096	$(10,770)	$128,663
Net Income (Loss)	$152,720	$70,837	$(13,111)	$210,446
Total Assets	$7,309,267	$3,544,162	$477,012	$11,330,441
Capital Spending	$184,019	$95,396	$9,905	$289,320

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)				
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
Income from Continuing Operations	$154,366	$17,365	$21,324	$63,778
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 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
2004				
Operating Revenues	$1,551,356	$968,938	$967,805	$1,268,593
Operating Income	$267,692	$230,635	$94,660	$156,966
Income from Continuing Operations	$120,929	$42,823	$17,500	$56,369
Net Income	$120,552	$38,066	$15,973	$54,746
Earnings per Share, basic	$.83	$.26	$.11	$.37
Earnings per Share, diluted	$.82	$.26	$.11	$.37
Dividends per Share	$.26	$.26	$.26	$.275
Average Common Shares Outstanding, basic	146,085	146,148	146,385	146,597
Average Common Shares Outstanding, diluted	146,428	146,596	146,807	147,015
Common Stock Price (1)				
High	$25.49	$26.05	$25.25	$27.08
Low	$22.29	$21.85	$23.48	$24.75

(1) Our common stock is listed on the New York Stock Exchange. The number of shareholders of record was 31,461 at December 31, 2005.

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 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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.

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, 2005 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, 2005, 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

New York, New York

March 1, 2006

ENERGY EAST CORPORATION

SCHEDULE II - Consolidated Valuation and Qualifying Accounts

Years Ended December 31, 2005, 2004 and 2003

Classification	Beginning of Year	Additions	Write-offs (1)	Adjustments(2)	End of Year
(Thousands)					
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
2003					
Allowance for Doubtful Accounts - Accounts Receivable	$58,640	$47,919	$(48,211)	$(5,500)	$52,848

(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.

Selected Financial Data

Rochester Gas and Electric Corporation

	2005	2004	2003	2002	2001
(Thousands)					
Operating Revenues	$1,105,526	$1,034,057	$1,025,110	$992,940	$1,039,476
Depreciation and amortization	$72,858	$89,822	$105,901	$102,758	$112,643
Other taxes	$65,396	$74,912	$82,045	$89,370	$87,718
Interest Charges, Net	$56,445	$54,831	$75,947	$59,838	$62,416
Net Income	$78,989	$70,317	$29,640	$50,067	$73,650
Capital Spending	$55,450	$81,717	$101,453	$123,591	$147,639
Total Assets	$2,382,273	$2,320,357	$2,960,830	$2,632,396	$2,453,007 (1)
Long-term Obligations and Redeemable Preferred Stock(2)	$697,951	$697,465	$850,261	$777,254	$812,243

(1) Does not reflect the reclassification of accrued removal costs from accumulated depreciation to a regulatory liability.

(2)

All of RG&E's redeemable preferred stock was redeemed in 2004.

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

Electric Delivery Rate Overview and Electric Delivery Business Developments

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.

Electric Rate Plans: See Energy East's Item 7 - MD&A - Electric Delivery Rate Overview for this discussion.

RG&E Transmission Project: See Energy East's Item 7 - MD&A - Electric Delivery Business Developments, for this discussion.

Niagara Power Project Relicensing: See Energy East's Item 7 - MD&A - Electric Delivery Business Developments - Niagara Power Project Relicensing, for this discussion.

Other Proceedings on the NYPSC Collaborative on End State of Energy Competition: See Energy East's Item 7 - MD&A - Electric Delivery Rate Overview and Electric Delivery Business Developments, for this discussion.

NYISO Billing Adjustment: See Energy East's Item 7 - MD&A - Electric Delivery Business Developments, for this discussion.

Errant Voltage: See Energy East's Item 7 - MD&A - Electric Delivery Business Developments, for this discussion.

Hurricanes' Effects on Natural Gas Supply: See Energy East's Item 7 - MD&A - Electric Delivery Business Developments, for this discussion.

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

Rochester Gas and Electric Corporation

Natural Gas Delivery Rate Overview and Natural Gas Delivery Business Developments

RG&E's natural gas delivery business consists of transporting, storing and distributing natural gas.

Natural Gas Rate Plans: See Energy East's Item 7 - MD&A - Natural Gas Delivery Rate Overview for this discussion.

Natural Gas Supply Agreements: See Energy East's Item 7 - MD&A - Natural Gas Delivery Business Developments, for this discussion.

Other Proceedings on the NYPSC Collaborative on End State of Energy Competition: See Energy East's Item 7 - MD&A - Electric Delivery Rate Overview and Electric Delivery Business Developments, for this discussion.

Manufactured Gas Plant Remediation Recovery: See Energy East's Item 7 - MD&A - Natural Gas Delivery Business Developments, for this discussion.

Hurricanes' Effects on Natural Gas Supply: See Energy East's Item 7 - MD&A - Natural Gas Delivery Business Developments, for this discussion.

Other Matters

New Accounting Standard

FIN 47

: In March 2005 the FASB issued FIN 47, which 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 effective December 31, 2005, as required. RG&E's application of FIN 47 did not have a material effect on its financial position, results of operations or cash flows. (See Item 8 - Note 1 to RG&E's Financial Statements.)

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

Rochester Gas and Electric Corporation

Contractual Obligations and Commercial Commitments

At December 31, 2005, RG&E's contractual obligations and commercial commitments are:

	Total	2006	2007	2008	2009	2010	After 2010
(Thousands)							
Contractual Obligations							
Long-term debt[1]	$1,343,790	$41,424	$41,424	$91,424	$138,504	$30,904	$1,000,110
Operating leases	33,234	4,495	4,487	4,182	3,982	3,947	12,141
Nuclear plant obligations	137,299	2,042	2,042	1,123	-	-	132,092
Unconditional purchase obligations:							
Electric	1,860,022	213,975	250,528	224,979	230,488	242,615	697,437
Natural gas	135,517	50,226	47,137	36,476	1,672	2	4
Pension and other postretirement benefits[2]	498,417	43,870	43,141	43,426	44,202	46,550	277,228
Total Contractual Obligations	$4,008,279	$356,032	$388,759	$401,610	$418,848	$324,018	$2,119,012

(1) Amounts for long-term debt include future interest payments. Future interest payments on variable-rate debt are determined using the rates at December 31, 2005.

(2)

Amounts are through 2015 only.

Critical Accounting Estimates

See Energy East's Item 7 - MD&A - Critical Accounting Estimates, for discussions of Statement 71, Goodwill and Other Intangible Assets, Pension and Other Postretirement Benefit Plans, Unbilled Revenues and Allowance for

Doubtful Accounts.

Liquidity and Capital Resources

Operating Activities

: Cash flows from operating activities included refunds to RG&E customers of $25 million in 2005 and of $60 million in 2004, from proceeds from the sale of Ginna, pursuant to the Electric Rate Agreement. The Electric Rate Agreement requires additional refunds to customers of $15 million in 2006 and $10 million in 2007.

Investing Activities

: Capital spending totaled $56 million in 2005, $82 million in 2004 and $101 million in 2003, including nuclear fuel in 2004 and 2003. 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.

Capital spending is projected to be $182 million in 2006, is expected to be paid for principally with cash on hand and internally generated funds and will be primarily for the same purposes described above, as well as RG&E's transmission project. Construction of the transmission project is expected to begin in the first quarter of 2006. (See Item 8 - Note 8 to RG&E's Financial Statements.)

Financing Activities

: 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 2010 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 replaced its previous revolving credit facility, in which it was a joint borrower with NYSEG, in June 2005. That facility provided for maximum borrowings of $230 million in the aggregate at December 31, 2004, under which RG&E was permitted to borrow up to $75 million.

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 no short-term debt outstanding at December 31, 2005 and 2004.

RG&E declared common dividends of $35 million in the first quarter of 2005 and an additional $35 million in the third quarter of 2005.

Capital Structure at December 31,	2005	2004	2003
Long-term debt[(1)]	54.5%	54.7%	50.0%
Preferred stock	-	-	4.4%
Common equity	45.5%	45.3%	45.6%
	100.0%	100.0%	100.0%

(1) Includes current portion of long-term debt

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 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 of 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

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

Rochester Gas and Electric Corporation

that, at December 31, 2005, 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 retail customers choice in their electricity supply including fixed and variable rate options and an option to purchase electricity supply from an ESCO. Approximately 75% 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. RG&E uses 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 includes 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.

As of February 15, 2006, the portion of RG&E's load for fixed rate option customers in excess of the load supplied by owned generation and long-term contracts is 100% hedged for on-peak and off-peak periods in 2006. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change RG&E's earnings less than $100 thousand in 2006. RG&E's percentage of 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.

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

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

Rochester Gas and Electric Corporation

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.)

Results of Operations

	2005	2004	2003
(Thousands)			
Operating Revenues	$1,105,526	$1,034,057	$1,025,110
Operating Income	$168,389	$265,775	$120,826
Earnings Available for Common Stock	$78,989	$68,528	$26,765

Earnings

RG&E's earnings for 2005 increased $10 million compared to 2004. Improved results in 2005 for the electric operating segment totaling $22 million were due to the Electric Rate Agreement that took effect in 2004, higher delivery volumes and earnings on electric commodity service and were partially offset by the effect of the one-time benefit of $10 million experienced in 2004 as a result of the sale of Ginna and the approval of RG&E's Electric and Natural Gas Rate Agreements.

RG&E's earnings for 2004 increased $42 million compared to 2003 primarily as a result of:

- Additional earnings of $23 million as a result of one-time and ongoing effects from RG&E's Electric and Natural Gas Rate Agreements, including ratemaking treatment for the sale of Ginna. The one-time effects, which added $10 million, include the flow-through of excess deferred taxes and ITCs and the elimination of certain reserves established pending regulatory determination. Ongoing effects added $13 million to earnings, and include increases as a result of RG&E's electric retail access surcharge and natural gas merchant function charge, and annual credits from the ASGA as provided in RG&E's Electric Rate Agreement.
- The effect of a $30 million reduction in earnings for 2003 due to the recognition of terms and conditions of an NYPSC rate order for RG&E effective January 2003, including $26 million for excess electric earnings and related interest.

Those increases were partially offset by:

- A $13 million decrease from lower electric revenue, exclusive of the effects of RG&E's Electric Rate Agreement.

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

Rochester Gas and Electric Corporation

Other Items

Pension Income

: Periodic pension income is included in other operating and maintenance expenses and reduces the amount of expense that would otherwise be reported. Other operating and maintenance expenses would have been $11 million lower for 2005 and $2 million higher for 2004 if periodic pension income had not changed compared to the prior year. RG&E had no funding requirements in 2005 and anticipates no funding requirements in 2006 since total plan assets exceed the projected benefit obligation. (See Item 8 - Note 12 to RG&E's Financial Statements.)

	2005	2004	2003
($ in Millions)			
Periodic pension income (pretax)	$10	$21	$19
As a percent of net income	8%	18%	38%

Other (Income)

: (See Item 8 - Note 1 to RG&E's Financial Statements.) Changes for 2005 and 2004 include:

- A decrease of $7 million in Other (Income) for 2005 primarily due to the effect of a $6 million increase in 2004 from RG&E's Electric and Natural Gas Rate Agreements.

Interest Charges, Net

: Interest charges, net decreased $21 million in 2004 primarily due to the effect of $21 million of interest expense incurred in 2003 related to the recognition of the terms and conditions of the NYPSC rate order for RG&E, discussed above.

Operating Results for the Electric Delivery Business

	2005	2004	2003
(Thousands)			
Megawatt-hours			
Retail Deliveries	7,488	7,008	6,979
Retail Commodity Sales (1)	4,068	4,598	4,798
Wholesale sales	3,138	2,477	1,885
Operating Revenues	$691,159	$664,794	$676,678
Operating Expenses	$565,201	$439,992	$596,501
Operating Income	$125,958	$224,802	$80,177

(1)

Included in retail deliveries.

Operating Revenues

: The $26 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $52 million in wholesale sales, resulting primarily from increased volume,
- An increase of $39 million from sales of electricity; higher market prices increased revenue by $74 million, partially offset by $35 million resulting from lower commodity sales volume.
- An increase of $14 million for higher delivery volume, and
- An increase of $39 million in other revenue primarily related to accruals to recover purchased power costs.

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Those increases were partially offset by:

- A decrease of $95 million resulting from lower transition charges. Transition charges decline as market prices for RG&E's purchase entitlements increase, and
- A decrease of $22 million in other revenues, reflecting higher accruals for customer earnings sharing.

The $12 million decrease in operating revenues for 2004 was primarily the result of:

- A net reduction of $19 million due to a change in market structure that allows customers to choose other supply options. Retail revenues declined $123 million but that decrease was partially offset by higher wholesale revenues of $104 million.

Those decreases were partially offset by:

- Increases due to certain provisions of RG&E's Electric Rate Agreement, approved in May 2004, including a $4 million increase from a retail access surcharge and a $6 million increase as a result of various credits from amortization of the ASGA.

Operating Expenses

: The $125 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 costs as a result of the sale of Ginna in 2004, including a $63 million increase for purchases of power to replace power previously generated by Ginna, substantially offset by reductions of $37 million in other operating and maintenance expenses, $21 million in depreciation and $4 million in other taxes,
- An increase of $10 million due to certain credits to other operating expenses that resulted from the RG&E Electric Rate Agreement and reduced expenses in the second quarter of 2004, and

The $157 million decrease in operating expenses for 2004 was primarily the result of:

- A net decrease of $112 million due to the regulatory treatment of RG&E's gain on the sale of Ginna, which included the recognition of a $341 million pretax gain partially offset by the after-tax deferral of the gain of $229 million.
- The effect of the recognition of terms and conditions of an NYPSC rate order for RG&E, that became effective January 2003, that increased operating expenses $30 million in 2003.
- A $10 million decrease in operating and maintenance costs because of certain deferral petitions that were resolved as part of RG&E's Electric Rate Agreement.

- A $16 million decrease in fuel and purchase power from sources other than Ginna.

Those decreases in operating expenses were offset by:

- Cost increases resulting from the sale of Ginna and the subsequent purchases of 90% of the plant output amounting to $18 million. Purchases from CGG increased fuel and purchased power costs by $91 million in 2004. Operating costs, including depreciation and decommissioning, were reduced by $73 million.

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Rochester Gas and Electric Corporation

Operating Results for the Natural Gas Delivery Business

	2005	2004	2003
(Thousands)			
Retail Deliveries - Dekatherms	53,040	53,567	55,207
Operating Revenues	$414,367	$369,263	$348,432
Operating Expenses	$371,936	$328,290	$307,783
Operating Income	$42,431	$40,973	$40,649

Operating Revenues

: The $45 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $53 million due to higher natural gas purchase costs that were passed on to customers.

Those increases were partially offset by:

- A decrease of $6 million due to lower sales primarily due to lower usage per customer.

The $21 million increase in operating revenues for 2004 was primarily the result of:

- Higher market prices for natural gas purchased of $21 million that were passed on to customers.
- A $5 million increase as a result of the natural gas merchant function charge included in RG&E's Natural Gas Rate Agreement.

These increases are partially offset by:

- A $6 million decrease resulting from lower deliveries, primarily due to warmer weather in the first quarter.

Operating Expenses

: The $44 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $53 million due to higher natural gas purchase costs partially offset by $2 million for lower volumes, and $7 million from other items including reduced loss factors.

The $21 million increase in operating expenses for 2004 was primarily the result of:

- An increase in natural gas purchased because of higher market prices.

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2005	2004
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$28,752	$11,834
Investments available for sale	53,325	59,425
Accounts receivable and unbilled revenues, net	193,807	149,602
Fuel and natural gas in storage, at average cost	57,434	38,955
Materials and supplies, at average cost	13,204	8,085
Accumulated deferred income tax benefits, net	-	15,344
Derivative assets	21,597	4,167
Prepayments and other current assets	27,047	19,552
Total Current Assets	395,166	306,964
Utility Plant, at Original Cost		
Electric	1,258,330	1,231,128
Natural gas	572,943	557,472
Common	199,015	185,901
	2,030,288	1,974,501
Less accumulated depreciation	583,557	534,465
Net Utility Plant in Service	1,446,731	1,440,036
Construction work in progress	18,748	28,623
Total Utility Plant	1,465,479	1,468,659
Other Property and Investments, Net	11,634	12,649
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	183,039	209,345
Deferred income taxes	12,007	1,673
Environmental remediation costs	25,013	11,814
Unamortized loss on debt reacquisitions	14,336	10,979
Nonutility generator termination agreement	82,243	91,465
Other	127,867	143,638
Total regulatory assets	444,505	468,914
Other assets		
Prepaid pension benefits	48,368	37,896
Other	17,121	25,275

Total other assets	65,489	63,171
Total Regulatory and Other Assets	509,994	532,085
Total Assets	$2,382,273	$2,320,357

The

notes on pages II-101 through II-117 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2005	2004
(Thousands)		
Liabilities		
Current Liabilities		
Accounts payable and accrued liabilities	$123,145	$87,000
Interest accrued	9,830	9,295
Taxes accrued	16,438	12,448
Accumulated deferred income taxes, net	698	-
Other	37,958	47,830
Total Current Liabilities	188,069	156,573
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	182,346	172,505
Unfunded future income taxes	89,104	101,873
Gain on sale of generation assets	111,262	139,228
Natural gas hedges	21,969	4,184
Other	51,015	32,425
Total regulatory liabilities	455,696	450,215
Other liabilities		
Deferred income taxes	167,785	180,696
Nuclear waste disposal	108,570	105,391
Other postretirement benefits	80,045	76,396
Environmental remediation costs	36,506	26,357
Other	65,146	48,786
Total other liabilities	458,052	437,626
Total Regulatory and Other Liabilities	913,748	887,841
Long-term debt	697,951	697,465
Total Liabilities	1,799,768	1,741,879
Commitments and Contingencies	-	-
Common Stock Equity		
Common stock ($5 par value, 50,000 shares authorized, 38,886 shares outstanding at December 31, 2005 and 2004)	**194,429**	194,429
Capital in excess of par value	483,252	481,753
Retained earnings	28,549	19,560

Accumulated other comprehensive loss	(6,487)	(26)
Treasury stock, at cost (4,379 shares at December 31, 2005 and 2004)	**(117,238)**	(117,238)
Total Common Stock Equity	582,505	578,478
Total Liabilities and Stockholder's Equity	$2,382,273	$2,320,357

The

notes on pages II-101 through II-117 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Statements of Income

Year Ended December 31,	2005	2004	2003
(Thousands)			
Operating Revenues			
Electric	$691,159	$664,794	$676,678
Natural Gas	414,367	369,263	348,432
Total Operating Revenues	1,105,526	1,034,057	1,025,110
Operating Expenses			
Electricity purchased and fuel used in generation	296,009	225,607	152,131
Natural gas purchased	270,647	228,937	210,605
Other operating expenses	182,285	205,249	293,948
Maintenance	49,942	55,709	59,654
Depreciation and amortization	72,858	89,822	105,901
Other taxes	65,396	74,912	82,045
Gain on sale of generation assets	-	(340,739)	-
Deferral of asset sale gain	-	228,785	-
Total Operating Expenses	937,137	768,282	904,284
Operating Income	168,389	265,775	120,826
Other (Income)	(4,391)	(11,717)	(5,267)
Other Deductions	2,684	(983)	2,441
Interest Charges, Net	56,445	54,831	75,947
Income Before Income Taxes	113,651	223,644	47,705
Income Taxes	34,662	153,327	18,065
Net Income	78,989	70,317	29,640
Preferred Stock Dividends	-	1,789	2,875
Earnings Available for Common Stock	$78,989	$68,528	$26,765

The

notes on pages II-101 through II-117 are an integral part of the financial statements.

Rochester Gas and Electric Corporation
Statements of Cash Flows

Year Ended December 31,	2005	2004	2003
(Thousands)			
Operating Activities			
Net income	$78,989	$70,317	$29,640
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	140,099	166,468	178,589
Income taxes and investment tax credits deferred, net	(3,607)	37,945	2,502
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	(10,471)	(21,372)	(17,616)
Regulatory disallowance for excess earnings	-	-	44,051
Changes in current operating assets and liabilities			
Accounts receivable, net	(38,243)	4,655	(6,364)
Inventory	(23,598)	(10,479)	(9,304)
Prepayments	(8,521)	(4,839)	13,643
Accounts payable and accrued liabilities	60,297	6,168	2,324
Customer refund	(25,329)	(58,219)	-
Interest accrued	535	(2,246)	1,031
Taxes accrued	(1,235)	(74,776)	20,679
Other current liabilities	(19,816)	(1,548)	(13,320)
Other assets	(12,764)	(14,927)	(60,551)
Other liabilities	(908)	(38,691)	15,214
Net Cash Provided by Operating Activities	135,428	58,456	200,518
Investing Activities			
Sale of generation assets	-	453,678	-
Excess decommissioning funds retained	-	76,593	-
Utility plant additions	(55,450)	(81,717)	(101,453)
Nuclear generating plant decommissioning fund	-	(8,560)	(17,362)
Maturity of current investments available for sale	553,835	561,050	-
Purchases of current investments available for sale	(547,735)	(620,475)	-
Other	(346)	-	(4,578)
Net Cash (Used in) Provided by Investing Activities	(49,696)	380,569	(123,393)
Financing Activities			
Repayments of first mortgage bonds and preferred stock,			

including net premiums	-	(201,000)	(80,000)
Long-term note issuances, net of discount or premiums	-	-	74,174
Repayment of promissory notes	-	-	(79,935)
Book overdraft	1,186	3,296	-
Liquidating dividend	-	(75,000)	-
Dividends on common and preferred stock	(70,000)	(171,789)	(63,288)
Net Cash Used in Financing Activities	(68,814)	(444,493)	(149,049)
Net Increase (Decrease) in Cash and Cash Equivalents	16,918	(5,468)	(71,924)
Cash and Cash Equivalents, Beginning of Year	11,834	17,302	89,226
Cash and Cash Equivalents, End of Year	$28,752	$11,834	$17,302

The

notes on pages II-101 through II-117 are an integral part of the financial statements.

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

(Thousands)	Common Stock Outstanding $5 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total
Balance, January 1, 2003	38,886	$194,429	$555,889	$154,267	-	$(117,238)	$787,347
Net income				29,640			29,640
Equity contribution from parent			301				301
Dividends declared							
Preferred stock				(2,875)			(2,875)
Common stock				(60,000)			(60,000)
Balance, December 31, 2003	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)
	38,886	$194,429	$483,252	$28,549	$(6,487)	$(117,238)	$582,505

Balance, December 31, 2005

The

notes on pages II-101 through II-117 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 $54 million at December 31, 2005, and $40 million at December 31, 2004, and are shown net of an allowance for doubtful accounts of $13 million at December 31, 2005, and $21 million at December 31, 2004. Accounts receivable balances do not bear interest although late fees may be assessed. Bad debt expense was $4 million in 2005, $5 million in 2004 and $11 million in 2003.

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. During the third quarter of 2005 Energy East re-examined the set of estimates used for all the operating companies and determined that some operating companies, including RG&E, required changes to the assumptions used in determining their unbilled revenue estimates.

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.

During 2005 RG&E reduced its allowance for doubtful accounts by $8 million due to revised assumptions about the ability to collect accounts receivable based on its collection experience.

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 will defer any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

Notes to Financial Statements

Rochester Gas and Electric Corporation

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.

In March 2005 the FASB issued FIN 47, which 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. For calendar-year enterprises such as RG&E, FIN 47 was effective no later than December 31, 2005. 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.

RG&E's asset retirement obligation was $6 million at December 31, 2005, and includes RG&E's estimated conditional asset retirement obligation of $4 million. It primarily consists of obligations related to removal or retirement of: asbestos, polycholorinated biphenyl (PCB) contaminated equipment, gas pipeline and cast iron gas mains. RG&E's asset retirement obligation was $2 million at December 31, 2004, and primarily consisted of obligations related to cast iron gas mains. The table below presents the various amounts related to RG&E's asset retirement obligation as of December 31, 2005. Changes in the assumptions underlying the items shown could affect the balance sheet amounts and future costs related to the obligations.

As of December 31,	2005
(Thousands)	
Asset retirement obligation	$(5,805)
Regulatory asset	$3,541
Regulatory liability	$(288)
Increase in utility plant	$1,412
Decrease in accumulated depreciation	$1,140

RG&E's pro forma conditional asset retirement obligation was $3 million at December 31, 2004, and January 1, 2004.

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.

Supplemental Disclosure of Cash Flows Information	2005	2004	2003
(Thousands)			
Cash paid during the year ended December 31:			

Interest, net of amounts capitalized	$41,261	$49,283	$47,805
Income taxes, net of benefits received	$37,742	$76,053	$(28,885)

The amount of capitalized interest was less than $0.5 million in 2005 and 2004 and $3 million in 2003.

Notes to Financial Statements

Rochester Gas and Electric Corporation

Decommissioning expense:

Other operating expenses for 2004 and 2003 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.

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 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 2 years for its coal station to 29 years for its hydroelectric stations. RG&E's depreciation accruals were equivalent to 3.4% of average depreciable property for 2005 and 3.6% for 2004 and 2003.

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.

Income 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. ITCs are amortized over the estimated lives of the related assets.

Other (Income) and Other Deductions:

Year Ended December 31,	2005	2004	2003
(Thousands)			
Interest and dividend income	$(3,574)	$(3,653)	$(3,830)
2004 RG&E Electric and Natural Gas Rate Agreement	-	(6,117)	-

Miscellaneous	(817)	(1,947)	(1,437)
Total other (income)	$(4,391)	$(11,717)	$(5,267)
Miscellaneous	$2,684	$(983)	$2,441
Total other deductions	$2,684	$(983)	$2,441

Notes to Financial Statements

Rochester Gas and Electric Corporation

Reclassifications

: Certain amounts have been reclassified in the financial statements to conform to the 2005 presentation.

RG&E revised the presentation of its investments in auction rate securities, classifying them as current investments available-for-sale rather than as cash and cash equivalents. RG&E held current investments of $53 million at December 31, 2005, and $59 million at December 31, 2004, 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 these current investments is recorded as interest income.

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.

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

Other regulatory assets consist primarily of deferred natural gas costs of $2 million, the deferred loss on the sale of RG&E's Oswego generating unit of $48 million that is being recovered through June 2013, RG&E's 2003 deferred ice storm costs of $32 million that are being recovered through April 2014, and deferred costs for RG&E's merger with Energy East of $24 million that are being recovered through December 2007. Other regulatory liabilities consist primarily of accrued earnings sharing amounts of $19 million that will be added to RG&E's ASGA and ultimately returned to customers.

Related party transactions:

RG&E conducts certain transactions with Energetix, Inc., a subsidiary of RGS Energy. Transactions between RG&E and Energetix, Inc. are primarily for the purchase of commodity and delivery services for both electricity and natural gas at tariff rates, and for related administrative services. The following table provides a summary of RG&E's revenues from sales to Energetix, Inc:

Year Ended December 31,	2005	2004	2003
(Millions)			
Electric revenue	-	$7	$132
Natural gas revenue	$1	$13	$24

Utility Shared Services Corporation and Energy East Management Corporation provide various administrative and management services to Energy East's operating utilities, including RG&E,

Notes to Financial Statements

Rochester Gas and Electric Corporation

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 for 2004 and 2005 and Energy East Management Corporation for 2003 through 2005 was approximately $22 million in 2005, $26 million in 2004 and $16 million in 2003.

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, 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

Notes to Financial Statements

Rochester Gas and Electric Corporation

Other Deductions as appropriate. RG&E records changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities. RG&E had $22 million of derivative assets all of which were current and $4 million of derivative liabilities, of which $3 million were noncurrent, at December 31, 2005. At December 31, 2004, it had $5 million of derivative assets, including $4 million current and $1 million long-term; and $5 million of derivative liabilities, all of which were current.

RG&E uses quoted market prices to determine the fair value of derivatives.

As of December 31, 2005, 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 150

: In May 2003 the FASB issued Statement 150, which requires that certain financial instruments be classified as liabilities in statements of financial position. Under previous guidance such instruments could be classified as equity. RG&E adopted Statement 150 as of July 1, 2003, and classified as a liability, rather than as equity, its $25 million of mandatorily redeemable preferred stock (which RG&E redeemed in 2004). RG&E also began to recognize as interest expense distributions that it had previously recognized as preferred stock dividends. The adoption of Statement 150 did not have a material effect on RG&E's financial position, results of operations or cash flows.

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, 2005 and 2004. Estimated amortization expense for intangible assets is $78 thousand for each of the next five years, 2006 through 2010.

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 4. Income Taxes

Year Ended December 31,	2005	2004	2003
(Thousands)			
Current			
Federal	$32,337	$72,446	$16,314
State	7,520	(5,924)	(752)
Current taxes charged to expense	39,857	66,522	15,562
Deferred			
Federal	(5,631)	75,231	624
State	1,624	17,702	3,574
Deferred taxes charged to expense	(4,007)	92,933	4,198
ITC adjustment	(1,188)	(6,128)	(1,695)
Total	$34,662	$153,327	$18,065

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

Year Ended December 31,	2005	2004	2003
(Thousands)			
Tax expense at statutory rate	$39,778	$78,276	$16,697
Depreciation and amortization not normalized	1,434	(4,238)	5,224
ITC amortization	(1,188)	(6,128)	(1,695)
State taxes, net of federal benefit	5,944	7,656	1,835
Cost of removal not normalized	(2,066)	(2,623)	(2,679)
Audit settlement, reserve for disputed items	(208)	(636)	(4,088)
ASGA, Ginna	-	80,075	-
Consolidated federal tax allocation	(5,568)	(149)	-
Other, net	(3,464)	1,094	2,771
Total	$34,662	$153,327	$18,065

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 for 2004 differed from the expected annual effective tax rate primarily as a result of the deferred gain from the sale of Ginna. RG&E recorded pretax income of $112 million and income tax expense of $112 million.

Notes to Financial Statements

Rochester Gas and Electric Corporation

At December 31, 2005 and 2004, RG&E's deferred tax assets and liabilities consisted of:

	2005	2004
(Thousands)		
Current Deferred Income Tax Assets (Liabilities)		
Derivative Assets	$(7,989)	-
	7,291	$15,344
Other		
Total Current Deferred Income Tax Assets (Liabilities)	(698)	$15,344
Noncurrent Deferred Income Tax Liabilities		
Depreciation	$203,188	$201,824
Unfunded future income taxes	20,341	17,562
Accumulated deferred ITC	7,985	9,173
Deferred (gain) loss on sale of generation assets	(49,200)	(49,189)
Statement 106 postretirement benefits	(31,632)	(27,550)
Pension	29,882	25,658
Derivative Liability	(9,734)	-
Other	(15,052)	1,545
Total Noncurrent Deferred Income Tax Liabilities	155,778	179,023
Less amounts classified as regulatory liabilities		
Deferred income taxes	(12,007)	(1,673)
Noncurrent Deferred Income Tax Liabilities	$167,785	$180,696

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, 2005 and 2004, RG&E's long-term debt was:

	Interest Rates	Maturity	2005	2004
			(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	3.00%	2032	10,500	10,500
PCN 2004 Series B	3.395%	2032	50,000	50,000
Series VV	6.375%	2033	75,000	75,000
Total first mortgage bonds			571,500	571,500
Pollution control notes, fixed				
1998 Series A	5.95%	2033	25,500	25,500
Pollution control notes, variable				
1997 Series A	3.10%	2032	34,000	34,000
1997 Series B	3.10%	2032	34,000	34,000
1997 Series C	2.90%	2032	33,900	33,900
Total pollution control notes, variable			101,900	101,900
Unamortized discount on debt			(949)	(1,435)
			697,951	697,465
Less debt due within one year, included in current liabilities			-	-
Total			$697,951	$697,465

[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, 2005, long-term debt, including sinking fund obligations (in thousands), that will become due during the next five years is:

2006	2007	2008	2009	2010
-	-	$50,000	$100,000	-

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 2010 and required fees on undrawn borrowing capacity. RG&E has no liability for any other

Notes to Financial Statements

Rochester Gas and Electric Corporation

joint borrower. RG&E's maximum borrowing limit under the facility is $100 million. At December 31, 2004, RG&E and NYSEG had a joint five-year $230 million revolving credit facility with certain banks, which was replaced by the current facility. RG&E pays a facility fee of 12.5 basis points annually on its current revolver sublimit.

RG&E uses drawings on its credit facility to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. RG&E had no short-term debt outstanding at December 31, 2005 or 2004.

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. 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, 2005, RG&E's ratio of total indebtedness to total capitalization was 0.55 to 1.00. No borrower is 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, 2005, 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

: RG&E has commitments in connection with its capital spending program. Capital spending in 2006 is expected to be paid for principally with cash on hand and internally generated funds. The program is subject to periodic review and revision. RG&E's capital spending will be primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements, governmental mandates and its transmission project.

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 $203 million for nuclear entitlement power in 2005, $139 million in 2004 and $45 million in 2003. RG&E estimates that its nuclear entitlement power purchases will be $203 million in 2006, $243 million in 2007, $225 million in 2008, $230 million in 2009, and $243 million in 2010.

Notes to Financial Statements

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.

FERC issued an order directing the NYISO to modify certain energy prices for May 8 and 9, 2000, and to back bill NYISO market participants, including RG&E. The NYISO and many market participants filed requests for rehearing with the FERC concerning that order. While the FERC has not ruled on those requests for rehearing, on July 8, 2005 and October 7, 2005, the NYISO issued back billings that reflected the FERC order concerning the May 2000 issues. RG&E's updated back billing relating to May 8 and 9, 2000 was approximately $1 million. In the third quarter of 2005 RG&E deferred the amounts associated with the back billing as a regulatory mandate, pursuant to its Electric Rate Agreement approved by the NYPSC.

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 eight sites where gas was manufactured in the past. All 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 eight sites ranges from $35 million to $71 million at December 31, 2005. 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.

Notes to Financial Statements

Rochester Gas and Electric Corporation

RG&E's liability to investigate and perform remediation, as necessary, at its known inactive gas manufacturing sites was $35 million at December 31, 2005, and $20 million at December 31, 2004.

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.

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,	2005		2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
Noncurrent investments - classified as available-for-sale	$11,374	$11,374	$12,297	$12,297
First mortgage bonds	$571,500	$629,990	$570,065	$642,972
Pollution control notes, fixed	$25,500	$27,745	$25,500	$28,305
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, 2004	2004 Change	Balance December 31, 2004	2005 Change	Balance December 31, 2005
(Thousands)					
Unrealized (losses) on investments:					
Unrealized holding (losses) during period, net of income tax benefit of $19 for 2005				$(29)	
Net unrealized (losses) on investments	-	-	-	(29)	$(29)
Minimum pension liability adjustment, net of income tax benefit of $2,538 for 2005	-	-	-	(3,827)	(3,827)
Unrealized (losses) on derivatives qualified as hedges:					
Unrealized (losses) during period on derivatives qualified as hedges, net of income tax benefit of $150 for 2005		$(26)		(200)	
Reclassification adjustment for (gains) included in net income, net of income tax expense of $1,595 for 2005				(2,405)	
Net unrealized (losses) on derivatives qualified as hedges	-	(26)	$(26)	(2,605)	(2,631)
Accumulated Other Comprehensive Loss	-	$(26)	$(26)	$(6,461)	$(6,487)

(See Risk management in Note 1.)

Notes to Financial Statements

Rochester Gas and Electric Corporation

Note 12. Retirement Benefits

RG&E sponsors defined benefit pension plans and postretirement benefit plans applicable to substantially all employees. RG&E uses a December 31 measurement date for its pension and postretirement benefit plans.

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$515,669	$547,622	$102,411	$102,143
Service cost	4,862	5,479	731	1,030
Interest cost	31,323	29,805	5,519	6,054
Actuarial loss (gain)	11,945	26,057	(15,304)	5,984
Divestitures	-	(52,070)	-	(6,765)
Benefits paid	(37,088)	(41,224)	(5,286)	(6,035)
Other	(17,626)	-	(5,299)	-
Benefit obligation at December 31	$509,085	$515,669	$82,772	$102,411
Change in plan assets				
Fair value of plan assets at January 1	$575,967	$607,824	-	-
Actual return on plan assets	38,362	60,190	-	-
Employer contributions	-	-	$5,286	$6,035
Divestitures	-	(50,823)	-	-
Benefits paid	(37,088)	(41,224)	(5,286)	(6,035)
Other	(34,886)	-	-	-
Fair value of plan assets at December 31	$542,355	$575,967	-	-
Funded status	$33,270	$60,298	$(82,772)	$(102,411)
Unrecognized net actuarial loss (gain)	831	(33,081)	(13,289)	5,828
Unrecognized prior service cost	14,267	10,679	5,052	7,191
Unrecognized net transition obligation	-	-	10,964	12,996
Prepaid (accrued) benefit cost	$48,368	$37,896	$(80,045)	$(76,396)

RG&E's accumulated benefit obligation for all defined benefit pension plans was $459 million at December 31, 2005, and $441 million at December 31, 2004. The sale of Ginna in 2004 resulted in a decrease in the projected benefit obligation of $52 million, and $51 million in pension funds were transferred as part of the sale.

RG&E's postretirement benefits were unfunded as of December 31, 2005 and 2004.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.50%	5.75%	5.50%	5.75%
Rate of compensation increase	4.00%	4.00%	N/A	N/A

As of December 31, 2005, RG&E decreased its discount rate from 5.75% to 5.50%. The discount rate is the rate at which the benefit obligations could presently be effectively settled.

Notes to Financial Statements

Rochester Gas and Electric Corporation

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.

	Pension Benefits			Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
(Thousands)						
Components of net periodic benefit cost						
Service cost	$4,862	$5,479	$6,285	$731	$1,030	$1,168
Interest cost	31,323	29,805	32,345	5,519	6,054	6,248
Expected return on plan assets	(45,148)	(49,184)	(51,292)	-	-	-
Unrecognized transition obligation	-	-	-	1,828	2,119	2,485
Amortization of prior service cost	1,483	1,262	1,462	859	1,141	1,339
Recognized net actuarial gain	(2,991)	(6,906)	(8,248)	(3)	(263)	(276)
Curtailment	-	(11,835)	-	-	7,401	-
Settlement charge	-	10,007	-	-	(7,007)	-
Net periodic benefit cost	$(10,471)	$(21,372)	$(19,448)	$8,934	$10,475	$10,964

Net periodic benefit cost is included in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount charged to expense 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 the transition obligation for postretirement benefits that resulted from the adoption of Statement 106 over 20 years.

Weighted-average assumptions used to determine net periodic benefit cost	Pension Benefits			Postretirement Benefits		
Year ended December 31,	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	6.25%	6.50%	5.75%	6.25%	6.50%
Expected 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's expected rate of return on plan assets assumption was developed based on a review of long-term historical returns for the major asset classes. That analysis also considered both current capital market conditions and projected future 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.

Notes to Financial Statements

Rochester Gas and Electric Corporation

RG&E assumed a 10.0% annual rate of increase in the per capita cost of covered health care benefits for 2006 that gradually decreases to 5.0% by the year 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 components	$5	$(7)
Effect on postretirement benefit obligation	-	$(51)

RG&E's weighted-average asset allocations at December 31, 2005 and 2004, by asset category, are:

	Pension Benefits		
Asset Category	Target Allocation	2005	2004
Equity securities	60%	64%	62%
Debt securities	30%	28%	32%
Real estate	5%	2%	-
Other	5%	6%	6%
Total	100%	100%	100%

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 a 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, 2005 and 2004.

RG&E does not anticipate any contributions to its pension fund in 2006.

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 as follows:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2006	$35,289	$8,581	$241
2007	$34,626	$8,515	$229
2008	$34,579	$8,847	$235

2009	$35,051	$9,151	$240
2010	$37,069	$9,481	$239
2011 - 2015	$227,241	$49,987	$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)			
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
2003			
Operating Revenues	$676,678	$348,432	$1,025,110
Depreciation and Amortization	$88,822	$17,079	$105,901
Interest Charges, Net	$65,011	$10,936	$75,947
Income Taxes	$3,206	$14,859	$18,065
Net Income	$14,437	$15,203	$29,640
Total Assets	$2,350,350	$610,480	$2,960,830
Capital Spending	$74,024	$27,429	$101,453

Note 14. Quarterly Financial Information (Unaudited)

Quarter Ended	March 31	June 30	September 30	December 31
(Thousands)				
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
2004				
Operating Revenues	$313,346	$223,729	$234,100	$262,882
Operating Income	$59,852	$148,995	$27,869	$29,059
Net Income	$25,940	$28,929	$5,416	$10,032
Earnings Available for Common Stock	$25,427	$27,614	$5,455	$10,032

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, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005 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.

PricewaterhouseCoopers LLP

New York, New York

March 1, 2006

ROCHESTER GAS AND ELECTRIC CORPORATION

SCHEDULE II - Valuation and Qualifying Accounts

Years Ended December 31, 2005, 2004 and 2003

Classification	Beginning of Year	Additions	Write-offs [1]	Adjustments [2]	End of Year
(Thousands)					
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
2003					
Allowance for Doubtful Accounts - Accounts Receivable	$31,182	$11,310	$(11,310)	$(4,000)	$27,182

(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

Item 10. Directors and Executive Officers of the Registrants

Incorporated herein by reference to the information under the captions "Corporate Governance," "Committees," "Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance" in Energy East's Proxy Statement, which will be filed with the Commission on or before May 1, 2006.

Information regarding Directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 for RG&E is set forth in RG&E's Exhibit 99-1.

Information regarding executive officers of the registrants is on page I-15 of this report.

Item 11. Executive Compensation

Incorporated herein by reference to the information under the captions "Stock Performance Graph," "Executive Compensation," "Pension Plan Table," "Employment, Change in Control and Other Arrangements," "Directors' Compensation" and "Report of Compensation and Management Succession Committee" in Energy East's Proxy Statement, which will be filed with the Commission on or before May 1, 2006.

Information regarding executive compensation for RG&E is set forth in RG&E's Exhibit 99-1.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Incorporated herein by reference to the information under the caption "Security Ownership of Certain Beneficial Owners and Management" in Energy East's Proxy Statement, which will be filed with the Commission on or before May 1, 2006.

RGS Energy, a wholly-owned subsidiary of Energy East, is the beneficial owner of 100% of NYSEG's common stock and 100% of RG&E's common stock. Information regarding ownership of equity securities of Energy East is set forth in RG&E's Exhibit 99-1.

Item 13. Certain Relationships and Related Transactions

Incorporated herein by reference to the information under the caption "Election of Directors" in Energy East's Proxy Statement, which will be filed with the Commission on or before May 1, 2006.

None for RG&E.

Item 14. Principal Accounting Fees and Services

Incorporated herein by reference to the information under the captions "Independent Accountants," "Audit Fees," "Audit Related Fees," "Tax Fees" and "All Other Fees" in Energy East's Proxy Statement, which will be filed with the Commission on or before May 1, 2006.

Information regarding "Audit Fees", "Audit Related Fees", "Tax Fees" and "All Other Fees" for RG&E is set forth in RG&E's Exhibit 99-1.

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, 2005 and 2004

For the three years ended December 31, 2005:

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, 2005

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, 2005 and 2004

For the three years ended December 31, 2005:

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, 2005

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	3-4 -	By-Laws of the Company as amended January 10, 2006.
	(A)10-3 -	Amendment No. 1 to Director Share Plan.
	(A)10-4 -	Amendment No. 2 to Director Share Plan.
	(A)10-6 -	Amendment No. 1 to Deferred Compensation Plan - Director Share Plan.
	(A)10-10 -	Supplemental Executive Retirement Plan Amendment No. 3.
	(A)10-16 -	Amendment No. 1 to Deferred Compensation Plan.
	(A)10-26 -	Award Agreement (February 2006) under the 2000 Stock Option Plan.
	(A)10-27 -	Amended and Restated Director's Charitable Giving Program.
	(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.
Rochester Gas and Electric Corporation	23 -	Consent of PricewaterhouseCoopers LLP to incorporation by reference into a certain registration statement.
	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.
	99-1 -	Information regarding directors, Section 16(a) compliance, executive compensation, employment, change in control and other arrangements, security ownership of management, code of ethics and audit fees.

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

(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
	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
	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

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	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 -	Subordinated Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2001 - Company's 10-Q for the quarter ended September 30, 2001 - File No. 1-14766	4-4
	4-7 -	First Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2001, related to the Subordinated Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of July 24, 2001 - Company's 10-Q for the quarter ended September 30, 2001 - File No. 1-14766	4-5
	(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)10-5 -	Deferred Compensation Plan - Director Share Plan - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-39
	(A)10-7 -	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
	(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)10-11 -	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

Registrant	Exhibit No.	Filed in	As Exhibit No.
Energy East Corporation	(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)10-17 -	Amended and Restated Employment Agreement dated as of July 1, 2004, by and among the Company, Energy East Management Corporation and W. W. von Schack - Company's 10-Q for the quarter ended June 30, 2004 - File No. 1-14766	10-21
	(A)10-18 -	Employment Agreement dated February 8, 2002, by and among the Company, Energy East Management Corporation and K. M. Jasinski - Company's 10-K for the year ended December 31, 2001 - File No. 1-14766	10-15
	(A)10-19 -	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)10-20 -	Restricted Stock Plan - Company's 10-K for the year ended December 31, 1998 - File No. 1-14766	10-36
	(A)10-21 -	Restricted Stock Plan Amendment No. 1 - Company's 10-K for the year ended December 31, 2002 - File No. 1-14766	10-16
	(A)10-22 -	Form of Restricted Stock Award Grant - Company's 10-Q for the quarter ended March 31, 2005 - File No. 1-14766	10-23
	(A)10-23 -	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)10-24 -	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)10-25 -	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
	(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
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

Registrant	Exhibit No.	Filed in	As Exhibit No.
Rochester Gas and Electric Corporation	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
	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, dated as of June 16, 2005.

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, dated as of June 16, 2005 (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 JPMorgan Chase Bank), 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: March 1, 2006

By /s/ Robert D. Kump
Robert D. Kump
Vice President, Controller &
Chief Accounting Officer

ROCHESTER GAS AND ELECTRIC CORPORATION

Date: March 1, 2006

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: March 1, 2006

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

PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER

Date: March 1, 2006

By /s/Robert D. Kump
Robert D. Kump
Vice President, Controller &
Chief Accounting Officer

Signatures

(Continued)

	ENERGY EAST CORPORATION, continued
Date: March 1, 2006	By /s/John T. Cardis John T. Cardis, Director
Date: March 1, 2006	By /s/Joseph J. Castiglia Joseph J. Castiglia, Director
Date: March 1, 2006	By /s/Lois B. DeFleur Lois B. DeFleur, Director
Date: March 1, 2006	By /s/G. Jean Howard G. Jean Howard, Director
Date: March 1, 2006	By /s/David M. Jagger David M. Jagger, Director
Date: March 1, 2006	By /s/Seth A. Kaplan Seth A. Kaplan, Director
Date: March 1, 2006	By /s/Ben E. Lynch Ben E. Lynch, Director
Date: March 1, 2006	By /s/Peter J. Moynihan Peter J. Moynihan, Director
Date: March 1, 2006	By /s/Walter G. Rich Walter G. Rich, Director

Signatures

(Continued)

ROCHESTER GAS AND ELECTRIC CORPORATION
PRINCIPAL EXECUTIVE OFFICER

Date: March 1, 2006

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

PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER

Date: March 1, 2006

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

Date: March 1, 2006

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

Date: March 1, 2006

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 -	By-Laws of the Company as amended January 10, 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.
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	*4-6 -	Subordinated Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2001.
	*4-7 -	First Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2001, related to the Subordinated Indenture between the Company and JPMorgan

Chase Bank, as Trustee, dated as of July 24, 2001.

*(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.

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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.
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	* (A)10-18 -	Employment Agreement dated February 8, 2002, by and among the Company, Energy East Management Corporation and K. M. Jasinski.
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	*(A)10-20 -	Restricted Stock Plan.
	*(A)10-21 -	Restricted Stock Plan Amendment No. 1.
	*(A)10-22 -	Form of Restricted Stock Award Grant.
	*(A)10-23 -	Amended and Restated 2000 Stock Option Plan, effective October 15, 2003.
	*(A)10-24 -	Award Agreement under the 2000 Stock Option Plan.
	*(A)10-25 -	Award Agreement (February 2001) under the 2000 Stock Option Plan.
	(A)10-26 -	Award Agreement (February 2006) under the 2000 Stock Option Plan.
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	21 -	Subsidiaries.
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	Consent of PricewaterhouseCoopers LLP to incorporation by reference into certain registration statements.
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EXHIBIT INDEX (Continued)

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	*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.
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99-1 - Information regarding directors, Section 16(a) compliance, executive compensation, employment, change in control and other arrangements, security ownership of management, code of ethics and audit fees.

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

(A) Management contract or compensatory plan or arrangement.