ENERGY EAST CORP
Form 10-K
February 29, 2008
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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, 2007**

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	14-1798693

(Incorporated in New York)
52 Farm View Drive
New Gloucester, Maine 04260-5116
(207) 688-6300
www.energyeast.com

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

Title of each class	Name of each exchange on which registered
Common Stock (Par Value $.01)	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.

Yes __X__ No ____

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

Yes ____ No __X__

Indicate by check mark whether the 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 the 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. __X__

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer __X__ Accelerated filer ____

Non-accelerated filer ____ Smaller reporting company ____

(Do not check if a smaller reporting company)

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

Yes _____ No __X__

The aggregate market value of the common stock held by nonaffiliates of Energy East Corporation as of June 30, 2007, the last business day of Energy East's most recently completed second fiscal quarter, was $4.1 billion, based on the closing sale price as reported on the New York Stock Exchange.

The number of shares of common stock (Par value $.01 per share) outstanding as of February 15, 2008, was 158,302,145.

DOCUMENTS INCORPORATED BY REFERENCE

Document	10-K Part
Energy East Corporation has incorporated by reference certain portions of its Proxy Statement, which will be filed with the Commission on or before April 29, 2008.	III

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PART IV

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, LLC wholesale markets at times of high demand.

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

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

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

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

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

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

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

MNG

Maine Natural Gas Corporation is a small natural gas delivery company in Maine.

NHG New Hampshire Gas Corporation is a propane air delivery company in New Hampshire.

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.

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

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

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

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

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

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

Glossary of Terms

Abbreviations or acronyms frequently used in this report:

ALJ

Ginna

Administrative Law Judge

AMI advanced metering infrastructure, which includes smart meters

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

DIG Issue G26 Derivatives Implementation Group (DIG) Issue No. G26, "Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate"

DOE United States Department of Energy

DPUC Connecticut Department of Public Utility Control

Dth dekatherm

EITF 06-10 Emerging Issues Task Force Issue No. 06-10, "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements"

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

FERC Federal Energy Regulatory Commission

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

FSP FIN 39-1 FASB Staff Position No. FIN 39-1, "Amendment of FASB Interpretation No. 39"

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

Iberdrola is one of the largest electric utilities and the largest renewable energy provider in the world. Its services reach 22 million points of supply, with over nine million in Spain. Its operations include generation, transmission, distribution and marketing of electricity and natural gas

ISO-NE ISO New England Inc.

ITC investment tax credit

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

MDPU Massachusetts Department of Public Utilities

Merger The proposed transaction whereby Energy East will merge with Green Acquisition Capital, Inc., a direct, wholly-owned subsidiary of Iberdrola, S.A. and we would become a subsidiary of Iberdrola as provided for in the Merger Agreement

Merger Agreement The Agreement and Plan of Merger dated as of June 25, 2007, among Iberdrola, S.A., Green Acquisition Capital, Inc., a direct, wholly-owned subsidiary of Iberdrola, and Energy East

MPUC Maine Public Utilities Commission

MW, MWh megawatt, megawatt-hour

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

NBC nonbypassable wires charge

NRC United States Nuclear Regulatory Commission

NUG nonutility generator

Glossary of Terms (Continued)

NYISO

New York Independent System Operator

NYPA New York Power Authority

NYPSC New York State Public Service Commission

NYSDEC New York State Department of Environmental Conservation

NYSERDA New York State Energy Research and Development Authority

OPEB other post-employment benefits

PCB polychlorinated biphenyl

ROE return on equity

RTO Regional Transmission Organization

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

SAR stock appreciation right

SEC or the Commission United States Securities and Exchange Commission

SPDES State Pollutant Discharge Elimination System

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

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

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

Statement 123

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

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

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

Statement 141(R) Statement of Financial Accounting Standards No. 141 (revised 2007), *Business Combinations*

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

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

Statement 158 Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)*

Statement 159 Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, Including an amendment of FASB Statement No. 115*

Statement 160 Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*

VEBA voluntary employees' beneficiary association

Statement 109 Statement of Financial Accounting Standards No. 109, A*ccounting for Income Taxes*	**Voice Your Choice** RG&E's and NYSEG's electric commodity option programs

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 occurrence of any event, change or other circumstances that could give rise to the termination of the Merger Agreement with Iberdrola,
- the outcome of any legal or regulatory proceedings that have been instituted following the announcement of the Merger,
- our ability to compete in the rapidly changing and competitive electric and/or natural gas utility markets,
- increased state and FERC regulation,
- the operation of the NYISO and retroactive NYISO billing adjustments,
- the operation of ISO-NE as an RTO and CMP's continued participation in ISO-NE,
- our continued ability to recover NUG and other costs,
- changes in fuel supply or cost and the success of strategies to satisfy power requirements,
- our ability to expand our products and services including our energy infrastructure in the Northeast,
- the effect of rising commodity costs on customer usage and uncollectible expense,
- our ability to maintain enterprise-wide integration synergies,
- market risk from changes in value of financial or commodity instruments, derivative or nonderivative, caused by fluctuations in interest rates or commodity prices,
- the ability of third parties to continue to supply electricity and natural gas,
- our ability to obtain adequate and timely rate relief and/or the continuation of current rate plans,
- the possible discontinuation or further modification of fixed-price supply programs in New York,
- nuclear decommissioning or environmental incidents,
- legal or administrative proceedings,
- changes in the cost or availability of capital,
- economic growth or contraction in the areas in which we do business,
- extreme weather-related events such as floods, hurricanes, ice storms or snow storms,
- weather variations affecting customer energy usage,
- changes in authoritative accounting guidance,
- acts of terrorism,
- the effect of volatility in the equity and fixed income markets on the cost of pension and other postretirement benefits,
- the inability of our internal control framework to provide absolute assurance that all incidents of fraud or error will be detected and prevented, and
- other considerations that may be disclosed from time to time in our publicly disseminated documents and filings.

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

PART

I

Item 1. Business

General development of business

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

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.

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.

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.

CTG Resources'

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

RGS Energy's

wholly-owned subsidiaries are NYSEG and RG&E. NYSEG is a regulated utility primarily engaged in purchasing and delivering electricity and natural gas in the central, eastern and western parts of the state of New York. 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.

The Energy Network's

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

The following general developments have occurred in our businesses since January 1, 2007:

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

Merger Agreement with Iberdrola

On June 25, 2007, we announced that we had entered into a Merger Agreement with Iberdrola, a corporation organized under the laws of the Kingdom of Spain, and Green Acquisition Capital, Inc., a New York corporation that is a wholly-owned subsidiary of Iberdrola. On November 20, 2007, our shareholders approved the Merger Agreement.

The Merger Agreement provides for a business combination whereby we and our subsidiaries would become wholly-owned subsidiaries of Iberdrola and each outstanding share of our common stock will be converted into the right to receive $28.50 per share in cash, without interest. Consummation of the Merger is subject to customary conditions, including the absence of injunctions or restraints imposed by governmental entities, the receipt of required regulatory approvals and the absence of any material adverse event that would reasonably be expected to have a material adverse effect on Energy East.

For more discussion about the Merger, see Item 7 - MD&A - Recent Developments.

Regulation

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

Financial information about segments

See Item 8 - Note 14 to our Consolidated Financial Statements.

Narrative description of business

Principal business

Our principal business consists of our regulated electricity transmission and distribution operations in upstate New York and Maine and our regulated natural gas transportation, storage and distribution operations in upstate New York, Connecticut, Maine and Massachusetts. We serve approximately two million electricity customers and one million natural gas customers. Our service territories reflect diversified economies, including high-technology firms, insurance, light industry, consumer goods manufacturing, pulp and paper, ship building, colleges and universities, agriculture, fishing and recreational facilities. Our operating revenues derived from regulated electricity sales were 56% in 2007, 58% in 2006 and 56% in 2005. Operating revenues derived from regulated natural gas sales were 34% in 2007, 32% in 2006 and 34% in 2005. 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 872,000 electricity and 256,000 natural gas customers in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport.

RG&E's

principal business consists of its regulated electricity transmission, distribution and generation 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 360,000 electricity and 297,000 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.

CMP

conducts regulated electricity transmission and distribution operations in Maine serving approximately 600,000 customers in its service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

SCG

conducts natural gas transportation and distribution operations in Connecticut serving approximately 175,000 customers in its service territory of approximately 560 square miles with a population of approximately 808,000. SCG's service territory extends along the southern Connecticut coast from Westport to Old Saybrook and includes the 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 575 square miles with a population of approximately 706,000, principally in the greater Hartford-New Britain area and Greenwich.

Berkshire Gas

conducts natural gas distribution operations in western Massachusetts serving approximately 36,000 customers in its service territory of approximately 520 square miles with a population of approximately 220,000. Berkshire Gas' service territory includes the cities of Pittsfield and North Adams.

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

Other businesses

Our other businesses include retail energy marketing companies, a nonutility generating company, a FERC-regulated liquefied natural gas peaking plant, a natural gas delivery company, a propane air delivery company, telecommunications assets, a district heating and cooling system, and an energy consulting services company. We include their results of operation, 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. Revenues from the two companies accounted for approximately 10% of Energy East's total revenues in 2007, 2006 and 2005.

Cayuga Energy, Inc.

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

CNE Energy Services Group, Inc.

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

Energy East Enterprises, Inc.

includes MNG, a small natural gas delivery company and NHG, a propane air delivery company.

MaineCom Services

owns and leases fiber optic lines and provides telecommunications services in Maine.

TEN Companies, Inc.

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

The Union Water-Power Company

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

Sources and availability of raw materials

Electric

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

NYSEG satisfied the majority of its power requirements for 2007 through purchases under long-term contracts with NUGs, the New York Power Authority and Constellation Nuclear, LLC. A small portion of its requirements was satisfied 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 2007 through purchases under long-term contracts with the New York Power Authority, Constellation Nuclear, LLC, and Ginna Nuclear Power Plant, LLC. A small portion of its requirements was satisfied from its owned 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.

RG&E's 2008 coal requirements are expected to be approximately 114,000 tons and represents use by Russell Station until its planned closure in the second quarter of 2008 upon completion of RG&E's transmission project. RG&E's coal supply portfolio contains both spot and term agreements with multiple suppliers. In 2007, 73% of RG&E's coal requirements were purchased under contract and 27% was purchased on the spot market. RG&E maintains a reserve supply of coal ranging from 30 to 60 days.

Under a Maine state law, CMP was mandated to sell its generation assets and relinquish its supply responsibility. CMP no longer owns generating assets but retains its power entitlements under long-term contracts with NUGs and a power purchase contract with Entergy Nuclear Vermont Yankee, LLC. CMP sells its power entitlements under auctions approved by the MPUC. By its orders issued in December 2005, January 2007 and January 2008, the MPUC approved CMP's sale of its entitlements for various periods ranging from one to three years, through February 28, 2010. CMP's retail electricity prices are set to provide recovery of the costs associated with its ongoing power entitlement obligations, net of the revenue received under its entitlement sales. CMP's revenues and purchased power costs would increase if it were required to be the standard-offer provider of electricity supply for retail customers. There would be no effect on CMP's net income in such an event, however, because CMP is ensured cost recovery through Maine state law for any standard-offer obligations.

Natural Gas

NYSEG, RG&E, CNG, SCG, Berkshire Gas and MNG satisfied their 2007 natural gas supply requirements through purchases from large natural gas producers and other natural gas suppliers, natural gas storage capacity contracts and winter peaking supplies and resources. A majority of the natural gas supply purchased was acquired under long- and short-term supply contracts and the remainder was acquired on the spot market. The operating companies used long-term contracts for firm underground natural gas storage capacity. Firm transportation capacity was acquired under long-term contracts and was utilized to transport both natural gas supply purchased and natural gas withdrawn from storage to local distribution systems. Winter peaking supplies and resources are either owned by Energy East's operating companies or are contracted for under long-term arrangements.

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

Franchises

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

Seasonal business

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

Working capital

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

Competitive conditions

In New York, the NYPSC has implemented policies that require utilities to actively encourage customers to migrate to ESCO suppliers. NYSEG and RG&E filed proposed ESCO referral program parameters and draft tariffs pursuant to their respective rate cases. To date the NYPSC has not acted on those filings. NYSEG is currently participating in collaborative discussions pursuant to its Supply Service Joint Proposal to develop an ESCO introduction program targeting new small customers that seek to initiate service. If parties reach consensus on a program that is ultimately approved by the NYPSC, the ESCO introduction program would replace the NYSEG ESCO referral program pending before the NYPSC. NYSEG and RG&E are unable to predict the ultimate effect of the programs on their ability to continue to provide commodity service to their customers.

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

Research and development

Our consolidated expenditures for research and development were $5 million in 2007 and 2006, and $4 million in 2005. Expenditures were for internal research programs and contributions to research administered by the NYSERDA, the Electric Power Research Institute, the Gas Technology 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

We are subject to regulation by federal, state and local governmental entities 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 requiring environmental approval and certification of proposed major transmission facilities.

From time to time, environmental laws, regulations and compliance programs may require changes in our 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 $8 million to meet environmental requirements during the three years ended December 31, 2007. Future capital additions for current facilities to meet environmental requirements are not expected to be material. However, we have plans to voluntarily adopt a number of environmentally friendly initiatives, including an AMI. We would also have significant expenditures if we repower Russell Station using natural gas.

Water and air quality

: We 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.

We are required to comply with federal and state oil spill statutes and regulations including the Spill Prevention Control and Countermeasures (SPCC) regulations. Revisions to such regulations were recently finalized and require that we update current oil SPCC plans by July 1, 2009, and prepare new SPCC plans for locations that are covered under the regulations. The SPCC locations include electric operation service centers and substations, natural gas operation centers, liquefied natural gas facilities, Russell Station, Allegany Station and several RG&E and NYSEG hydroelectric generating stations.

We are required to comply with federal and state air quality statutes and regulations for operation of RG&E's 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 the second quarter of 2008 upon the completion of RG&E's transmission project, which will substantially reduce our emissions. RG&E is currently preparing applications for regulatory approvals to repower Russell Station using natural gas.

The 1990 Clean Air Act Amendments limit emissions of sulfur dioxide and nitrogen oxides and require emissions monitoring. The EPA allocates annual emissions allowances to RG&E's coal-fired generating station based on statutory emissions limits under Phase II (which began January 1, 2000) of the 1990 Amendments. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide.

A similar allowance program under Title I of the 1990 Amendments regulates nitrogen oxides emissions from RG&E's coal-fired station and a combustion turbine generating station. Another requirement of the 1990 Amendments is for the coal-fired station and a combustion turbine generating station to have a facility operating permit (Title V permit). The Title V permits required for each station have been granted.

In 2005 the EPA finalized rules requiring further reductions in sulfur dioxide and nitrogen oxides emissions, as well as mercury emissions from coal-fired generating stations. Methods to achieve the reductions will be proposed by the individually affected states. New York has submitted its mercury emissions control implementation plan to the EPA for approval. The first phase of New York's plan is scheduled to take effect in 2010. New York also has adopted and submitted a nitrogen oxides and sulfur dioxide emissions control implementation plan to the EPA for approval. The reductions for the first phase will begin in 2009 for nitrogen oxides and 2010 for sulfur dioxide, and the second phase for both pollutants will begin in 2015.

Regulations adopted by the state of New York that further limit acid rain precursor emissions from electric generating units, at an additional cost to us, 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.

RG&E purchases emissions allowances as necessary in order to comply with the Clean Air Act and New York state acid rain regulations and estimates its cost for allowances will be less than $1 million for 2008. 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.

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

New York has issued a draft of its RGGI rule that generally follows the model rule. One aspect of the rule is New York's proposal to auction 100% of allowances, with the proceeds to be used for "energy efficiency and clean energy technology purposes." Electricity generators would be required to purchase necessary allowances to continue operations and there would be an increase in the cost of the electricity produced by those generators. The final New York rule is expected by the second quarter of 2008.

In December 2007 the Maine Board of Environmental Protection (MBEP) adopted implementing regulations based on the model RGGI rule. Regulations require specific reductions and allowance purchases by affected emission sources in Maine and establish a framework for allowance trading and purchasing carbon dioxide offsets from eligible sources. The Maine regulations specify that all necessary carbon dioxide allowances must be purchased at auction and all auction proceeds will be held and managed by an independent trust. Auction proceeds will be used to fund energy efficiency and carbon dioxide emission reduction programs and to mitigate ratepayer impacts attributable to the trading program. As all allowances will be auctioned, affected electricity generators will be required to purchase necessary allowances to continue operations and there will likely be a corresponding increase in the cost of electricity produced by those generators and charged to electricity customers. We cannot predict the ultimate effect of this program on the price of electricity in Maine.

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

Number of employees

As of January 31, 2008, we had 5,837 employees.

Financial information about geographic areas

We 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 through our Web site. Access to these documents is available from the main page of our Internet Web site through "Financial Information" and then "Corporate Governance." Printed copies of these documents are also available upon request by contacting Investor Relations at (207) 688-4386.

Item 1A. Risk Factors

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

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There can be no assurance that Iberdrola's acquisition of the company will be completed.

Consummation of the proposed Merger is subject to satisfaction of various closing conditions, including obtaining the approvals or consents from a number of United States federal and state public utility, antitrust and other regulatory authorities described in the Merger Agreement. To date, all regulatory approvals have been received except approval from the NYPSC. The NYPSC staff has taken the its position that the Merger does not satisfy the standard under the New York Public Service Law for approval. We cannot predict whether NYPSC authorization will be obtained on satisfactory terms or the timing of that approval. If the Merger is not completed and the Merger Agreement is terminated, the market price of our common stock may decline to the extent that the current market price of our shares reflects an assumption as to the completion of the Merger. While the Merger is pending, we have agreed to operate our businesses in the ordinary course and certain significant business actions or changes from our ordinary course would require the consent of Iberdrola. In addition, until consummation (or termination) of the Merger, we are prohibited from declaring and paying dividends in excess of the current dividend rate of $0.31 per share per quarter.

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

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

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

Accordingly, we conduct all of our operations through those subsidiaries. Our ability to pay dividends on our common stock and to pay principal and accrued interest on our debt depends upon our receipt of dividends from our principal subsidiaries. Payments to us by those subsidiaries depend, in turn, upon their results of operation 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.

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

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

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

Our electric utility companies have substantial transmission capital investment programs including proposed transmission projects in Maine that could require investment in excess of $1 billion. The transmission projects are expected to increase reliability, meet new load growth requirements and interconnect with new generation, including renewable generation. The regulatory approval process for transmission projects is extensive and we may not be able to obtain the approvals required for these projects. Various factors beyond our control, including an increase in the cost of materials or labor, may increase the cost of completing construction projects and may delay construction.

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

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

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

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

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

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

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

We

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

We could recognize financial losses as a result of volatility in the market values of those 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 gains or losses and, if the differences exceed certain levels, could result in our hedges becoming ineffective under accounting guidance. Gains or losses on ineffective hedges are marked-to-market on our income statement without reference to our underlying sale of the commodity.

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

We pass commodity price increases on to electricity customers who receive default or variable price supply service and to all natural gas customers. We have a comprehensive hedging program in place to mitigate the price risk for the load requirements of electricity customers who choose a fixed price option under NYSEG's and RG&E's current commodity option programs. Higher prices that are passed on to customers can lead to higher bad debt expense and customer conservation resulting in reduced demand.

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

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

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

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

We are subject to extensive federal and state environmental regulation.

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

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

If any of our utility subsidiaries' credit ratings were downgraded, our ability to access the capital markets, including the commercial paper markets, could be adversely affected and our borrowing costs would increase. Some factors that affect credit ratings are cash flows, liquidity and the amount of debt as a component of total capitalization. A scenario that could cause a subsidiary's debt as a component of total capitalization to increase would be the need to borrow money to pay for unexpected repairs to its transmission and/or distribution systems due to a catastrophic event.

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

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

The NYPSC staff has raised certain issues with regard to NYSEG's and RG&E's earnings sharing calculations.

The NYPSC staff in its testimony in the Merger proceeding has alleged that NYSEG did not properly compute the amount due to customers under the electric earnings sharing mechanism (ESM) in NYSEG's electric rate plan that was in effect from 2002 through 2006. The staff claimed that its preliminary analysis shows an additional $67 million, including interest, should have been allocated to customers. The staff indicated that its analysis would be completed no later than NYSEG's next electric rate case. NYSEG vigorously disputes staff's claim. For each year 2002 through 2006 NYSEG made annual compliance filings, as required by the NYPSC. The NYPSC staff has never taken exception to those filings, including during the litigated rate proceeding that resulted in the NYPSC August 2006 rate order. NYSEG is unable to predict when or how the issue will be resolved. The staff also raised issues in the Merger proceeding with regard to the ESM under the RG&E electric rate plan currently in effect, but has not completed its analysis. RG&E believes that it has been properly calculating the amount due to customers in its annual compliance filings since 2004, but cannot predict how the matter will be resolved.

Current uncertainty in the auction rate securities markets is having a negative effect on both outstanding debt and investments.

NYSEG and RG&E have issued $776 million of tax-exempt pollution control notes, $518 million of which have rates that are reset periodically through an auction process that occurs every 7 days for $416 million and every 35 days for the remaining $102 million. The principal and interest on these notes are insured. The investors' source of liquidity on these notes is the auction market itself. As the financial strength of bond insurers has been called into question, due in part to their exposure to rising mortgage default rates, investors have reacted by withdrawing from the market, thereby significantly reducing market liquidity and resulting in higher and more volatile interest rates. More recently, as the market became illiquid and broker-dealers withdrew their capital support, an increasing percentage of the auctions, including NYSEG and RG&E auctions, have failed to receive sufficient bids to set new interest rates. In such instances, the issuer is obligated to pay a formulaic failure rate until sufficient bids are received at a scheduled auction. For NYSEG and RG&E, the interest rates resulting from

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failed auctions are a function of current short-term money market rates multiplied by a factor, ranging from 175% to 300%, based on the rating of the applicable bond insurer. To date, failed auction rates for NYSEG and RG&E have ranged from 3.3% to 10.5%. These rates are significantly higher than rates paid in previous auctions. Continued and prolonged illiquidity in the auction rate market could significantly increase our interest costs.

We have also invested in auction rate securities. A prolonged disruption in that market could result in a revaluation of those investments, which we have traditionally carried at par because they have been readily convertible to cash. We have reduced our exposure to those securities to $25 million at February 27, 2008, but cannot predict the effect of continued instability in the auction rate market on the valuation of those investments.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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

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

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

Our 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 - 6 locations	60
RG&E		Rochester, NY - 3 locations	50
RG&E	Coal-fired	Greece, NY	257 (1)
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 (2)
		Archbald, PA	
Total			558

(1) Russell Station is scheduled to close in the second quarter of 2008 upon completion of RG&E's transmission project.
(2) Cayuga Energy's 50.1% share of the generating capability.

CMP owns the following percentages of stock in three companies with previously operating nuclear generating facilities: Maine Yankee Atomic Power Company in Wiscasset, Maine, 38%; Yankee Atomic Electric Company in Rowe, Massachusetts, 9.5%; and Connecticut Yankee Atomic Power

Company in Haddam, Connecticut, 6%. The three facilities have been permanently shut down. Maine Yankee Atomic Power Company completed its decommissioning in 2005, Yankee Atomic Electric Company completed its decommissioning in 2006 and Connecticut Yankee Atomic Power Company completed its decommissioning in 2007. Each of the three facilities has an established NRC-licensed independent spent fuel storage installation on site to store spent nuclear fuel in dry casks until the DOE takes the fuel for disposal.

CMP owns 311 substations in the state of Maine having an aggregate transformer capacity of 6,862,205 kilovolt-amperes. The transmission system consists of 2,564 circuit miles of line. The distribution system consists of 22,140 pole miles of overhead lines and 1,324 miles of direct bury and network underground lines.

NYSEG owns 441 substations in the state of New York having an aggregate transformer capacity of 15,288,450 kilovolt-amperes. The transmission system consists of 4,400 circuit miles of line. The distribution system consists of 30,576 pole miles of overhead lines and 2,122 miles of direct bury and network underground lines.

RG&E owns 165 substations in the state of New York having an aggregate transformer capacity of 6,900,400 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.

Our operating utilities' natural gas systems consist of:

Operating Company	Location	Miles of Transmission Pipeline	Miles of Distribution Pipeline
NYSEG	New York State	72	7,809
RG&E	New York State	109	8,530
SCG	Connecticut	-	3,751
CNG	Connecticut	-	3,688
Berkshire Gas	Massachusetts	-	735
MNG	Maine	2	91
NHG (Propane air)	New Hampshire	-	28

NYSEG owns the Seneca Lake Natural Gas Storage Facility, which is able to store approximately 1.4 billion cubic feet of natural gas. It is a high-deliverability storage facility that can be filled to capacity in 20 days and fully withdrawn in 10 days.

A portion of our utility plant is subject to liens or mortgages securing certain of our subsidiaries' first mortgage bonds. None of CMP's, NYSEG's or CNG's utility plant is subject to liens or mortgages securing first mortgage bonds.

RG&E, Berkshire Gas and SCG have first mortgage bond indentures that constitute a direct first mortgage lien on substantially all of their respective properties. (See Item 8 - Note 5 to our Consolidated Financial Statements.)

Item 3. Legal Proceedings

See Item 7 - MD&A - Electric Delivery Rate Overview, Electric Delivery Business Developments, Natural Gas Delivery Rate Overview and Natural Gas Delivery Business Developments and Item 8 - Note 9 to our Consolidated Financial Statements.

The NYPSC, DPUC, MPUC and MDPU 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 9 to our Consolidated Financial Statements, therefore, 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. Consequently, we believe that the ultimate disposition of the matters referred to in the paragraphs of the Note referred to above will not have a material adverse effect on our results of operation, financial position or cash flows.

(a) On July 6, 2007, a purported class action complaint was filed in the Supreme Court of the State of New York for Kings County against the company and its directors. The complaint alleges that, among other things, the consideration for the proposed acquisition by Iberdrola is unfair and inadequate because it does not provide the company's stockholders with a sufficient premium for the company's common stock and the defendants have breached their fiduciary duty. The complaint seeks to enjoin the Merger in addition to an unspecified amount of damages. On September 26, 2007, the plaintiff and Energy East and its directors agreed, subject to confirmatory discovery and court approval, to settle the lawsuit. The settlement is based on Energy East's agreement to include certain additional disclosures in its proxy statement. As a result of the settlement, plaintiff will not seek to enjoin the transaction. The settlement, if approved by the court, will result in dismissal with prejudice of the lawsuit. The settlement also will result in a release of claims that have been or could have been asserted relating to the Merger, the Merger Agreement, or any disclosures relating to the Merger by the plaintiff and the purported class of Energy East shareholders. In connection with such settlement, the plaintiff's counsel will apply to the court for attorneys' fees and expenses not to exceed in the aggregate $340,000, which Energy East has agreed to pay, if awarded by the court, provided the court approves the settlement and dismisses the lawsuit with prejudice. Energy East and its directors continue to deny all of the substantive allegations in the complaint.

(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 its Beebee and Russell generating stations without obtaining the required prevention of significant deterioration or new source review permits. The letter requested that RG&E provide the Attorney General's office with a large number of documents relating to this allegation. In January 2000 RG&E received a subpoena from the NYSDEC ordering production of similar documents. RG&E supplied documents and complied with the subpoena.

The NYSDEC served RG&E with a notice of violation in May 2000 alleging that between 1983 and 1987 RG&E completed five projects at Russell Station and two projects at Beebee Station, which is currently shut down, without obtaining the appropriate permits. RG&E maintains it has complied with the applicable rules and there is no basis for the Attorney General's and the NYSDEC's allegations. Beginning in July 2000 the NYSDEC, the Attorney General and RG&E had a number of discussions with respect to the resolution of the notice of violation. In October 2006 the Attorney General's office and the NYSDEC notified RG&E of their intention to file a complaint in federal court for violations involving Russell Station unless a settlement could be reached. Continued discussions led to a settlement agreement in December 2007 between the NYSDEC, the Attorney General's office and RG&E. To avoid the uncertainties and costs of litigation and to improve the environment, RG&E agreed to pay a $200,000 civil penalty and fund $500,000 for environmentally beneficial projects to be administered by the NYSERDA.

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RG&E also agreed to restrictions on the use and sale of federal sulfur dioxide emission allowances and plans to close Russell Station in the second quarter of 2008 upon completion of RG&E's transmission project. A consent decree was issued accepting the settlement in February 2008.

(c) The state of Connecticut filed suit in February 2007 against Energy East and its affiliates - TEN Companies, CNG and CTG Resources - for an alleged $14 million overcharge for heating and cooling services supplied to state buildings since 1992. Subsequently, the state increased its overcharge claim to $30 million. In January 2008 the state filed a motion for injunctive relief to prevent TEN Companies from exercising its right to allow each of the various heating and cooling contracts to expire on their respective expiration dates, and to require TEN Companies to continue to provide heating and cooling service under the agreements. While we believe that there is no merit to these actions, we cannot predict their outcome.

(d) In January 2008, the trustee in the SGF Chapter 7 bankruptcy proceeding brought adversarial proceedings against NYSEG Solutions, Inc., Carthage Energy, LLC., Cayuga Energy, Inc. and The Energy Network, Inc. seeking repayment of alleged preferential payments made in the one year period preceding the bankruptcy filing to those SGF affiliates in amounts totaling $14 million. We are evaluating the claims and plan to file responsive pleadings by April 1, 2008. We do not believe there is merit to the claims, but cannot predict the outcome of this proceeding.

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

Energy East's Special Meeting of Stockholders was held on November 20, 2007. The following matter was voted on:

A proposal to adopt the Agreement and Plan of Merger, dated as of June 25, 2007, among Iberdrola, S.A., Green Acquisition Capital, Inc. and Energy East Corporation.

Shares For:	103,981,778
Shares Against:	7,141,886
Shares Abstain:	1,131,960
Broker Non-Voted:	-

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Executive Officers of the Registrant

(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, 2007.

Energy East Corporation

Name and Position	Age	Period served	Business experience - January 2003 to date
Wesley W. von Schack	63	to date	Chairman, President & Chief Executive Officer
Chairman, President & Chief			

Executive Officer			
Robert E. Rude Senior Vice President and Chief Regulatory Officer	54	2005 to date to 2005	Senior Vice President and Chief Regulatory Officer Vice President and Controller
Richard R. Benson Senior Vice President and Chief Administrative Officer	50	2007 to date 2005 to 2007 2004 to 2005 to 2004	Senior Vice President and Chief Administrative Officer Vice President and Chief Administrative Officer Vice President, Administrative Services of Energy East Management Corporation Vice President, Human Resources of Energy East Management Corporation
Robert D. Kump Senior Vice President and Chief Financial Officer	46	2007 to date 2005 to 2007 to 2005	Senior Vice President and Chief Financial Officer Vice President, Controller and Chief Accounting Officer Vice President, Treasurer and Secretary
F. Michael McClain Senior Vice President and Chief Development and Integration Officer	58	2007 to date 2005 to 2007 2003 to 2005	Senior Vice President and Chief Development and Integration Officer Vice President - Finance, Treasurer and Chief Integration Officer Vice President, Finance and Chief Integration Officer of Energy East Management Corporation
Paul K. Connolly, Jr. Vice President - General Counsel	63	2006 to date to 2005	Vice President - General Counsel Partner - LeBoeuf, Lamb, Greene and MacRae LLP
Angela Beddoe Vice President, Public Affairs of Energy East Management Corporation	43	to date	Vice President, Public Affairs of Energy East Management Corporation

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

Name and Position	Age	Period served	Business experience - January 2003 to date
James P. Laurito	51	2005 to date	President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas

President and Chief Executive Officer of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation			and Electric Corporation
		2004 to 2005	President of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation
		2003 to 2004	President and Treasurer of New York State Electric & Gas Corporation

Central Maine Power Company

Name and Position	Age	Period served	Business experience - January 2003 to date
Sara J. Burns President and Chief Executive Officer of Central Maine Power Company	52	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 2003 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	57	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
		to 2004	President, Chief Executive Officer and Treasurer of The Berkshire Gas Company

Karen L. Zink	50	2004 to date	President, Treasurer & Chief Operating Officer of The Berkshire Gas Company
President, Treasurer & Chief Operating Officer of The Berkshire Gas Company		2003 to 2004	Vice President and General Manager 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.

If the Merger becomes effective, Mr. von Schack's employment agreement will be amended to provide for a two-year term from the date the Merger becomes effective, during which term he will continue to serve as the company's Chairman, President & Chief Executive Officer. The term may be extended for an additional one-year period with the consent of Mr. von Schack, Iberdrola and the company.

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.

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PART

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Item 5. Market for Registrant's 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 27,733 at January 31, 2008.

Quarter Ended	March 31	June 30	September 30	December 31
2007				
Dividends Declared per Share	$.30	$.30	$.30	$.31
Common Stock Price				
High	$25.93	$27.00	$27.10	$27.90
Low	$23.60	$22.11	$24.83	$26.75
2006				
Dividends Declared per Share	$.29	$.29	$.29	$.30
Common Stock Price				
High	$25.57	$25.39	$25.20	$25.66
Low	$22.98	$22.18	$23.36	$23.62

Equity Compensation Plan Information

The following table provides information as of December 31, 2007, 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)	4,033,510	$25.00	6,152,785
Equity Compensation Plan Not Approved by Stockholders (Restricted Stock Plan) [(1)]	NA	NA	651,653
Total	4,033,510	$25.00	6,804,438

(1)

See Item 8 - Note 11 to our Consolidated Financial Statements for information regarding the Restricted Stock Plan.
NA - not applicable

Issuer Purchases of Equity Securities

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, 2007 to October 31, 2007)	4,159[(1)]	$27.69	-	-

Month #2 (November 1, 2007 to November 30, 2007)	4,178[1]	$27.47	-	-
Month #3 (December 1, 2007 to December 31, 2007)	5,690[1]	$27.30	-	-
Total	14,027	$27.47	-	-

(1)

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

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Item 6. Selected Financial Data

	2007	2006	2005	2004	2003
(Thousands, except per share amounts)					
Operating Revenues	$5,178,108	$5,230,665	$5,298,543	$4,756,692	$4,514,490
Depreciation and amortization	$277,490	$282,568	$277,217	$292,457	$299,430
Other taxes	$255,680	$249,834	$246,271	$252,860	$269,238
Interest Charges, Net	$275,938	$308,824	$288,897	$276,890	$284,482
Net Income[1]	$251,298	$259,832	$256,833	$229,337	$210,446
Earnings per Share, basic[1]	$1.62	$1.77	$1.75	$1.57	$1.45
Earnings per Share, diluted[1]	$1.61	$1.76	$1.74	$1.56	$1.44
Dividends Declared per Share	$1.21	$1.17	$1.115	$1.055	$1.00
Average Common Shares Outstanding, basic	154,801	146,962	146,964	146,305	145,535
Average Common Shares Outstanding, diluted	155,805	147,717	147,474	146,713	145,730
Utility Capital Spending	$444,009	$408,231	$331,294	$299,263	$289,320
Total Assets	$11,878,709	$11,562,401	$11,487,708	$10,796,622	$11,330,441
Long-term Obligations,					

Capital Leases and Redeemable Preferred Stock	$3,877,029	$3,726,709	$3,667,065	$3,797,685	$4,017,846

(1) Income from Continuing Operations is $237,621 for 2004 and $208,490 for 2003. EPS from Continuing Operations, basic is $1.63 for 2004 and $1.43 for 2003. EPS from Continuing Operations, diluted is $1.62 for 2004 and $1.43 for 2003.

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

Overview

For a discussion of our Merger Agreement with Iberdrola whereby we will become a wholly-owned subsidiary of Iberdrola upon completion of the Merger, see Recent Developments.

Energy East's primary operations, our electric and natural gas utility operations, are subject to rate regulation established predominantly by state utility commissions. The approved regulatory treatment on various matters significantly affects our results of operation, financial position and cash flows. We have rate plans for NYSEG's natural gas segment, RG&E, CMP and Berkshire Gas that currently allow for recovery of certain costs, including stranded costs, and provide stable rates for customers and revenue predictability. Where rate plans are not in effect, or as we approach the end of the term of existing plans, we monitor the adequacy of rate levels and file for new rates when necessary. NYSEG's new electric rates went into effect on January 1, 2007. CNG's new rates became effective April 1, 2007. CMP's rate plan expired at the end of 2007 and NYSEG's natural gas rate plan and RG&E's electric and natural gas rate plans have terms that extend at least through the end of 2008. Under certain conditions those rate plans may continue.

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

We expect to make significant capital investments to enhance the safety and reliability of our distribution systems and to meet the growing energy needs of our customers in an environmentally responsive manner. Capital spending is expected to approximate $4 billion through 2012, including $660 million in 2008. Major spending programs include the installation of an AMI in New York and Maine requiring an investment of approximately $360 million; in excess of $1 billion of transmission investments, predominantly in Maine; a high efficiency transformer replacement program; and a "green" fleet initiative. The majority of our planned transmission investments will be pursuant to a regional reliability planning process. We will also be seeking approval for the repowering of Russell Station using natural gas, at a potential investment of approximately $425 million. We estimate that about one-half of our capital spending program will be funded with internally generated funds and the remainder through the issuance of a combination of debt and equity securities.

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 in an environmentally sensitive manner. Our operating companies have become increasingly efficient through realization of merger-enabled synergies.

We intend to augment this strategic focus by addressing many of the precepts of the Energy Policy Act of 2005 including investing in: a) transmission to increase reliability, meet new load growth and connect new, renewable generation to the grid; b) an AMI to promote customer conservation and peak load management; c) our distribution infrastructure to make it more efficient by reducing losses; and d) new regulated generation to the extent that it is approved by state legislators or regulators.

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

Recent Developments

On June 25, 2007, we announced that we had entered into a Merger Agreement with Iberdrola, a corporation organized under the laws of the Kingdom of Spain, and Green Acquisition Capital, Inc., a New York corporation that is a wholly-owned subsidiary of Iberdrola. On November 20, 2007, our shareholders approved the Merger Agreement.

The Merger Agreement provides for a business combination whereby we and our subsidiaries would become wholly-owned subsidiaries of Iberdrola and each outstanding share of our common stock will be converted into the right to receive $28.50 per share in cash, without interest.

Iberdrola is one of the world's largest energy companies with more than 22 million points of supply and 26,000 employees. Iberdrola is a leading owner and operator of renewable energy facilities, having an installed capacity of over 7,000 MW of wind generation (the largest wind portfolio in the world) and almost 10,000 MW of hydro generation. In the United States, Iberdrola jointly owns and operates the largest wind facility on the East Coast - Maple Ridge in upstate New York - and has over 20,000 MW of renewable generation under development in the United States.

Consummation of the Merger is subject to various customary closing conditions, including the absence of injunctions or restraints imposed by governmental entities, the receipt of required regulatory approvals and the absence of any event that would reasonably be expected to have a material adverse effect on Energy East. To date, all regulatory approvals have been received except approval from the NYPSC. We expect the Merger to be completed in the first half of 2008. Until the Merger is completed, Energy East will continue to operate as a separate company.

On January 11, 2008, ten active parties, including the NYPSC staff, filed testimony in the Merger approval proceeding in New York. Generally, testimony from parties other than the NYPSC staff either supports the transaction or recommends that certain conditions be imposed if the transaction is approved. The NYPSC staff's testimony concludes that the Merger is not in the public interest and should be denied as filed because the petitioners have not demonstrated quantifiable positive benefits. However, the staff does outline "essential conditions" including an extensive set of "positive benefit adjustments," divestiture of generation assets and utility financial protections, that may allow this transaction to meet the public interest standard, in its view.

The petitioners - Iberdrola, Energy East, NYSEG and RG&E - filed rebuttal testimony on January 31, 2008, in response to the positions of the staff and other parties. The petitioners contend that Iberdrola will provide significant benefits to the state of New York and NYSEG and RG&E customers in that Iberdrola possesses immense financial strength, global utility expertise, is the largest renewable energy provider in the world and has committed to supporting economic development and maintaining utility jobs in upstate New York. The petitioners believe Iberdrola is uniquely positioned to assist the state of New York in meeting its renewable energy policies and brings significant benefits to the state. Hearings were scheduled to begin in February 2008; however, the parties to the proceeding, including the NYPSC staff, have entered settlement discussions and hearings have been postponed for several weeks pending the outcome of those discussions. We cannot predict the outcome of this proceeding.

Electric Delivery Rate Overview

Our electric delivery business consists primarily of our regulated electricity transmission, distribution and generation operations in upstate New York and Maine. The electric industry is regulated by various state and federal agencies, including state utility commissions and the FERC. The following is a brief overview of the principal rate agreements in effect for each of our electric utilities. (See Electric Delivery Business Developments for a discussion of ongoing proceedings that could affect current rate agreements.)

New electric delivery rates for NYSEG took effect as of January 1, 2007. The new rates resulted in an annualized decrease in delivery rates of $36 million. Rates are based on an ROE of 9.55% and an equity ratio of 41.6%. In 2007 NYSEG was allowed an earnings collar for supply of plus or minus $5 million pretax with sharing outside the collar of 80% to customers and 20% to shareholders. NYSEG's supply earnings, net of sharing, were $6 million after tax. NYSEG's supply service program has been modified for 2008 as described in Electric Delivery Business Developments below.

RG&E's current rates were established by the 2004 Electric Rate Agreement, which addresses RG&E's electric rates through at least 2008. Key features of the Electric Rate Agreement include electric delivery rates that are frozen through December 2008. The Electric Rate Agreement also includes an earnings-sharing mechanism that allows customers and shareholders to share equally in electric business earnings, including supply service, above a 12.25% ROE target. Earnings levels were sufficient to generate $10 million of pretax sharing for 2007 and $11 million of pretax sharing for both 2005 and 2006. On February 1, 2008, RG&E made a required filing with the NYPSC requesting approval to continue the current rates and provisions of RG&E's electric rate plan beyond 2008.

NYSEG and RG&E currently offer their retail customers choice in their electricity supply including a fixed rate option, a variable rate option under which rates vary monthly based on the actual cost of electricity purchases and an option to purchase electricity supply from an ESCO. Both NYSEG's and RG&E's customers make their supply choice annually. Those customers who do not make a choice are served under a variable or default price option. Customers also pay an NBC, which includes recovery of stranded costs. The table below shows the percentages of load served under the various commodity supply options in 2007 and the projections for 2008.

	NYSEG		RG&E	
	2008	2007	2008	2007
Fixed Price Option	12%	17%	18%	21%
Variable Price Option or Default Supply Option	49%	45%	33%	29%
Energy Service Company Option	39%	38%	49%	50%

CMP's distribution costs were recovered under the ARP 2000, which became effective January 1, 2001, and expired on December 31, 2007, with price changes, if any, occurring on July 1 each year. CMP's annual delivery rate adjustments were based on inflation with productivity offsets of 2.75% in 2006 and 2.9% in 2007. The 2007 price change resulted in an annual revenue increase of $4 million.

CMP uses formula rates for transmission that are FERC regulated. The formula rates provide for the recovery of CMP's cost of owning, operating and maintaining its local and regional transmission facilities and local control center, including a FERC-approved base level ROE of 10.9%, plus a 50 basis point adder for regional facilities and a 100 basis point adder applicable to regional facilities placed in service after December 31, 2003, and approved as part of the ISO-NE regional planning process. The formula rates are updated annually based on June 1st filings to the FERC. CMP's transmission rates decreased approximately $7 million for the rate year effective June 1, 2007. The decrease resulted primarily from lower transmission congestion costs and a transmission refund requirement previously reserved by CMP.

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. On June 12, 2007, the MPUC approved a settlement implementing an annual stranded cost reconciliation in which CMP reduced its stranded cost rates by $4 million effective July 1, 2007. New stranded cost rates will go into effect on March 1, 2008. CMP is prohibited by state law from providing commodity service to its customers.

Electric Delivery Business Developments

NYSEG's Supply Service Filing

: On August 29, 2007, the NYPSC approved a proposal for revisions to NYSEG's commodity supply service in a joint proposal submitted by NYSEG, NYPSC staff and other interested parties. Provisions of the Supply Service Joint Proposal as adopted include:

- Continuation of supply service options for customers including taking service from an ESCO, taking service from NYSEG under a Fixed Price Option (FPO) and taking service from NYSEG under various variable price options, depending on the size of the customer.
- Customers would choose their supply service option annually.
- The variable rate options will continue to be the default service for customers that do not choose to take service from an ESCO or from NYSEG under the FPO.
- The commodity component of the FPO will be calculated and set annually as under the current commodity program; however, the cost allowance used to set the supply rate will increase. The cost allowance is the margin over projected market prices.
- NYSEG will absorb any losses that are experienced under the FPO and will retain the first $10 million (pretax) of earnings, with sharing above that amount at 85% to customers and 15% to shareholders.

The provisions of the Supply Service Joint Proposal became effective on January 1, 2008, and will remain in place for a three-year term, unless modified as part of an electric delivery rate case prior to that time.

In approving the Supply Service Joint Proposal, the NYPSC also established a new proceeding to develop revenue decoupling mechanisms for both the electric and natural gas segments of the business. By notice issued October 22, 2007, the NYPSC consolidated the revenue decoupling proceeding with the request for approval of the acquisition of Energy East by Iberdrola.

NYPSC Proceeding on NYSEG's Accounting for OPEB

: In August 2006 the NYPSC issued its decision in the NYSEG electric rate case. Among other things, the NYPSC instructed the ALJ to open a separate proceeding regarding the NYPSC staff's position that NYSEG should have retained $57 million of interest in its OPEB reserve and used it to reduce rate base

rather than to reduce OPEB expenses. In July 2007 NYSEG, the NYPSC staff and various intervenors filed

a joint proposal with the NYPSC resolving all outstanding issues in this matter. On September 20, 2007, the NYPSC approved the joint proposal. The joint proposal provided that NYSEG would refund to customers $17 million from its existing ASGA account and establish an external VEBA trust fund for already-reserved OPEB costs, which are currently deducted from rate base, of approximately $112 million. NYSEG completed the $17 million refund in December 2007. NYSEG contributed $60 million to the VEBA on October 4, 2007, and $52 million on January 15, 2008. The joint proposal also requires pretax charges to earnings for regulatory purposes of $8 million in 2007, $5 million in 2008 and $4 million in 2009. The charges in 2008 and 2009 are expected to be offset by earnings on the VEBA assets.

NYPSC Staff Allegations Concerning Earnings Sharing Calculations

: The NYPSC staff in its testimony in the Merger proceeding has alleged that NYSEG did not properly compute the amount due to customers under the electric ESM in NYSEG's electric rate plan that was in effect from 2002 through 2006. The staff claims that its preliminary analysis shows an additional $67 million, including interest, should have been allocated to customers. The staff indicated that its analysis would be completed no later than NYSEG's next electric rate case. NYSEG vigorously disputes the staff's claim. For each year 2002 through 2006 NYSEG made annual compliance filings, as required by the NYPSC. The NYPSC staff has never taken exception to those filings, including during the litigated rate proceeding that resulted in the NYPSC August 2006 rate order. NYSEG is unable to predict when or how the issue will be resolved. The staff also raised issues in the Merger proceeding with regard to the ESM under the RG&E electric rate plan currently in effect, but has not completed its analysis. RG&E believes that it has been properly calculating the amount due to customers in its annual compliance filings since 2004, but cannot predict how the matter will be resolved.

Niagara Power Project Allocations

: At its meeting on July 31, 2007, the NYPA's board of trustees approved a resolution calling for the extension of NYSEG's and RG&E's Niagara and St. Lawrence contracts with the NYPA through June 30, 2008, subject to early termination by the NYPA on at least 30 days' prior written notice. The NYPA executed the contract extensions with NYSEG and RG&E in late August 2007. Under the contract extensions, the allocations to the two companies were slightly reduced from a total of 508 MWs to a total of 451 MWs. The value of the NYPA power to NYSEG's and RG&E's residential ratepayers in 2007 was approximately $118 million.

Advanced Metering Infrastructure

: In response to an August 2006 NYPSC order, NYSEG and RG&E filed a plan to install an AMI (which include smart meters) for all of their electric and natural gas customers. Smart meters would provide customers with detailed consumption data, enabling them to better control their energy usage. Smart meters would also eliminate the need for routine manual meter readings and estimated bills, improve the companies' response to service interruptions, improve the gas balancing and settlement process, and create opportunity for a wide range of time-differentiated rates, load management and load aggregation programs that are expected to reduce peak loads and thereby defer the need for additional electric generation sources. In May 2007 NYSEG and RG&E filed a supplemental plan that includes updated cost estimates for NYPSC review and approval. The plan calls for a capital investment totaling approximately $268 million through 2010. NYSEG and RG&E had requested approval for rate treatment to be effective January 1, 2008, but because the NYPSC is still reviewing the filing, they have requested a postponement.

NYPSC could act on this matter during the second quarter of 2008, but there is no assurance that the proposal will be approved.

RG&E Transmission Project

: In December 2004 RG&E received approval from the NYPSC to upgrade its electric transmission system in order to provide sufficient transmission and ensure reliable service to customers in anticipation of the shutdown of the Russell Station. The project includes building or rebuilding 38 miles of transmission lines and upgrading substations in the Rochester, New York area. Construction on the project began in the first quarter of 2006 and is expected to be completed by May 2008. The estimated cost of the project is approximately $125 million.

Resolution of Threatened Litigation for Russell Station

: See Item 3 - Legal Proceedings - subsection (b).

CMP Alternative Rate Plan 2008

: On May 1, 2007, CMP submitted a filing to the MPUC proposing a new alternative rate plan for a seven-year term beginning January 1, 2008 (referred to as ARP 2008). CMP's current ARP 2000 ended on December 31, 2007. CMP's proposal retains the basic structure of ARP 2000, including annual price changes based on a specified inflation index less a predetermined productivity offset, service quality indicators and associated penalties for failure to achieve the performance targets, and explicit provisions for the recovery of certain exogenous or mandated costs. The filing proposes to maintain the existing rates at the termination of ARP 2000 as the initial rates for ARP 2008. The first price change under the proposed rate plan would occur on July 1, 2008. The proposal includes fixed productivity offset values of 0.25% for the initial two years of the rate plan and 0.50% for the remaining five years. It utilizes reserve accounting mechanisms to address recovery of costs associated with major storm restoration and environmental clean-up costs for manufactured gas sites and PCB-contaminated facilities. CMP's ARP 2008 proposal also incorporates incremental investment and operating expenses for new initiatives including an AMI project to deploy smart meters.

On February 8, 2008, the MPUC staff filed its updated testimony and recommended an annual rate decrease of $39 million. On the same date, the Office of the Public Advocate (OPA) filed testimony recommending a rate decrease of $22 million. The recommended price decreases result from lower cost of capital recommendations, higher sales expectations and no investment in AMI. The OPA recommends a five-year rate plan while the staff recommended no long-term rate plan. Hearings are scheduled in March 2008 and the MPUC is expected to reach a decision in the case in May 2008. CMP cannot predict the outcome of this proceeding.

April 2007 Storms

: CMP experienced two significant storms in April 2007 that resulted in extensive outages for its customers and significant damage to its distribution facilities. CMP incurred approximately $11 million in incremental costs to restore electric service to its customers after the storms. CMP estimates that it is entitled to recover approximately $5 million of those costs under ARP 2000 and has deferred that amount as a regulatory asset. CMP plans to request recovery of the $5 million in its final compliance filing under ARP 2000, which it expects to make on March 15, 2008.

Stranded Cost Reset

: On October 1, 2007, CMP submitted a filing to the MPUC proposing to revise CMP's stranded cost revenue requirement and rates. CMP proposes to establish stranded cost rates for a three-year period commencing March 1, 2008, with a continuation of current mechanisms for annual reconciliation of actual stranded cost expense and rate recovery. On January 25, 2008, CMP submitted updated stranded cost estimates based on the negotiated termination of a NUG purchase agreement, new contract rates for the resale of NUG contract entitlements and updated projections of future wholesale market prices. On February 12, 2008, the MPUC approved a settlement that reflected the January 25 update, which provided for a $57 million annual reduction in stranded costs effective March 1, 2008.

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 2008, 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.

Nonutility Generation

: We expensed approximately $529 million for NUG power in 2007 and estimate that our combined NUG power purchases will total $393 million in 2008, $230 million in 2009, $85 million in 2010, $86 million in 2011 and $79 million in 2012. 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 2007, averaged 10.9 cents per kilowatt-hour for CMP and 11.5 cents per kilowatt-hour for NYSEG. Recovery of the NUG costs is provided for in CMP's stranded cost rates and in NYSEG's rates through an NBC. (See Item 8 - Note 8 to our Consolidated Financial Statements.)

MPUC Inquiries into Continued Participation in New England RTO

: Maine lawmakers have enacted legislation requiring the MPUC to undertake an inquiry concerning whether or not CMP and other Maine electric utilities should continue to participate in the New England RTO, as operated by the ISO-NE. The MPUC has issued various reports to the Maine Legislature concerning continued participation, including the latest on January 15, 2008. As a result of this inquiry, the MPUC concluded that there are serious and valid concerns with the status quo regulatory structure of transmission projects in Maine and New England. The MPUC developed and assessed three options: market reform, a Maine Independent transmission company and a Maine/New Brunswick market. The Maine Legislature will consider this report during its 2008 session.

As part of the Merger approval in Maine, Iberdrola, Energy East and CMP agreed to take no action with regard to CMP's position in any RTO, including whether to extend, consent to, amend, or renew or otherwise modify the terms of CMP's contract with ISO-NE without explicit approval of the MPUC. The parties to the merger proceeding in Maine and the MPUC agreed that CMP will initiate and the MPUC will conduct a proceeding to determine if extension or renewal of CMP's contract with ISO-NE is in the public interest.

Any change in CMP's participation in the New England RTO could affect the process for siting and approval of new transmission investments and the cost recovery and rate of return for those investments.

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 that allows them 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.

NYSEG's Natural Gas Rate Plan, which became effective October 1, 2002, freezes overall delivery rates at least through December 31, 2008, and contains an earnings-sharing mechanism, a weather normalization adjustment mechanism and a gas cost incentive mechanism. All plan provisions may continue beyond 2008. The earnings-sharing mechanism requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in

excess of 12.5% through 2008. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $250 million. No sharing occurred in 2007, 2006 or 2005.

RG&E's current rates were established by the 2004 Natural Gas Rate Agreement, which addresses RG&E's natural gas rates at least through 2008. Key features of the Natural Gas Rate Agreement include natural gas delivery rates that are frozen through December 2008. The Natural Gas Rate Agreement also includes 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 allows customers and shareholders to share equally in earnings above a 12.0% ROE target. No sharing occurred in 2007, 2006 or 2005. On February 1, 2008, RG&E made a required filing with the NYPSC requesting approval to continue the current rates and provisions of RG&E's natural gas rate plan.

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

CNG's current rates became effective April 1, 2007, pursuant to a settlement agreement that is in effect through March 31, 2009. The settlement agreement increased base rates by a net of $14.4 million, or 4.0%, and provided for recovery of previously deferred costs including bad debts.

Berkshire Gas' current rate plan is a 10-year performance-based rate plan that runs through January 31, 2012. The plan has no ROE cap and has an annual inflationary rate adjustment that is determined based on the gross domestic product minus 1% as a productivity offset. The adjustment is made on September 1st each year. In July 2007 Berkshire Gas received an order from the MDPU pursuant to a midperiod review. The MDPU found that Berkshire Gas' rates are just and reasonable and that its plan should continue, without modifications, with successive annual adjustments through 2012.

Natural Gas Delivery Business Developments

Natural Gas Supply Agreements

: Our natural gas companies - NYSEG, RG&E, SCG, CNG, Berkshire Gas and MNG - each entered into a new three-year strategic alliance with Coral Energy Resources, beginning on April 1, 2007, to optimize transportation and storage services.

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. A trial was held in the fourth quarter of 2007 and a decision is anticipated in 2008. 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.

CNG Billing Issue

: In early February 2008 the DPUC opened an investigation regarding CNG's billing of certain customers during January 2008. Four of CNG's meter readers had intermittently and inappropriately approximated gas consumption for 3,000 customers during November and December 2007. The approximations were half of the actual usage by the customers. This led

to lower bills to the customers during November and December than actual usage would have produced. When actual readings were made in January 2008, the unbilled usage was picked up, resulting in higher bills than January usage would have produced. The Connecticut Attorney General has stated that CNG violated Connecticut law by erroneously billing customers in January 2008 for the full amount of the underbilling rather than pro-rating the amount over a number of months as Connecticut law requires. CNG believes that its practice is in accordance with Connecticut law but cannot predict the outcome of the proceeding.

New Accounting Standards

See Item 8 - Note 1 to our Consolidated Financial Statements for explanations about the following new accounting standards from the FASB and when they became or will become effective:

- Statement 157 issued in September 2006,
- DIG Issue G26 cleared in December 2006 and posted to the FASB website in January 2007,
- Statement 159 issued in February 2007,
- EITF 06-10 ratified in March 2007,
- FSP FIN 39-1 posted in April 2007, and
- Statement 141(R) and Statement 160 issued in December 2007.

Contractual Obligations and Commercial Commitments

At December 31, 2007, our contractual obligations and commercial commitments are:

	Total	2008	2009	2010	2011	2012	After 2012
(Thousands)							

Contractual Obligations							
Long-term debt[1]	$7,570,892	$339,596	$382,435	$484,282	$426,215	$749,489	$5,188,875
Capital lease obligations[1]	38,148	4,672	4,555	4,412	3,545	3,401	17,563
Operating leases	77,716	12,932	12,099	11,891	10,945	10,007	19,842
Nonutility generator power purchase obligations	1,263,280	392,868	230,439	84,759	86,117	78,734	390,363
Nuclear plant obligations	59,478	25,541	13,544	12,631	3,881	3,881	-
Unconditional purchase obligations:							
Electric	1,727,122	365,084	303,565	306,582	282,275	189,070	280,546
Natural gas	157,273	86,010	40,498	20,976	7,453	1,311	1,025
Pension and other postretirement benefits[2]	2,339,153	196,615	207,618	215,952	227,543	232,743	1,258,682
FIN 48 uncertain tax positions	23,492	14,854	8,638	-	-	-	-
Other long-term obligations	3,450	1,619	885	596	267	83	-
Total Contractual Obligations	$13,260,004	$1,439,791	$1,204,276	$1,142,081	$1,048,241	$1,268,719	$7,156,896

(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, 2007.
(2) Amounts are through 2017 only.
The above table excludes our regulatory liabilities, deferred income taxes, asset retirement obligation and environmental remediation costs because the related future cash flows are uncertain. See Item 8 - Notes 5, 6, 8 and 13 to our Consolidated Financial Statements for additional information regarding our financial commitments at December 31, 2007.

Critical Accounting Policies

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

Regulatory Assets and Liabilities

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

We believe our public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electric and natural gas operations in New York, Maine, Connecticut and Massachusetts; however, we cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC, MDPU 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 certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Approximately 90% of our revenue is 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

: We do not amortize goodwill, but test it for impairment at least annually. Impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. (See Item 8 - Note 3 to our Consolidated 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.

Our 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, 2007, we increased the discount rate from 5.75% to 6.00%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determine our discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations. (See Item 7 - MD&A - Other Market Risk and Item 8 - Note 13 to our Consolidated Financial Statements.)

Unbilled Revenues

: Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues. (See Item 8 - Note 1 to our Consolidated Financial Statements.)

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.)

Liquidity and Capital Resources

Cash Flows

The following table summarizes our consolidated cash flows for 2007, 2006 and 2005.

Year Ended December 31,	2007	2006	2005
(Thousands)			
Operating Activities			
Net income	$251,298	$259,832	$256,833
Noncash adjustments to net income	446,938	419,196	422,635
Changes in working capital	(127,716)	(199,315)	(90,796)
Other	(59,320)	(101,227)	(83,940)
Net Cash Provided by Operating Activities	511,200	378,486	504,732
Investing Activities			
Utility plant additions	(444,009)	(408,231)	(331,294)
Current investments available for sale, net	(157,045)	172,925	(57,270)
Other	(780)	7,547	20,133
Net Cash Used in Investing Activities	(601,834)	(227,759)	(368,431)
Financing Activities			
Net issuance of common stock	226,641	(5,764)	(3,838)
Net (repayments of) increase in debt and preferred stock of subsidiaries	45,776	(4,250)	26,448
Dividends on common stock	(178,090)	(167,349)	(150,367)

Net Cash Provided by (Used in) Financing Activities	94,327	(177,363)	(127,757)
Net Increase (Decrease) in Cash and Cash Equivalents	3,693	(26,636)	8,544
Cash and Cash Equivalents, Beginning of Year	93,373	120,009	111,465
Cash and Cash Equivalents, End of Year	$97,066	$93,373	$120,009

Operating Activities Cash Flows

: Net cash provided by operating activities was $511 million in 2007 compared to $378 million in 2006 and $505 million in 2005. The major contributors to the $133 million increase in cash provided by operating activities for 2007 were:

- A larger increase in accounts payable and accrued liabilities that increased cash by $167 million,
- A decrease in prepayments and other current assets that increased cash by $127 million,
- A decrease in inventory that increased cash by $23 million, and
- A decrease in taxes that increased cash by $80 million.

Those increases in cash flow were partially offset by:

- An increase in accounts receivable that decreased cash $180 million, and
- A $66 million increase in pension and OPEB contributions, primarily due to NYSEG's $60 million contribution to a VEBA in October 2007.

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The major items that contributed to the $126 million decrease in cash provided by operating activities for 2006 were:

- A reduction in accounts payable and accrued liabilities primarily due to payments for natural gas and electricity purchases and to refunds of amounts previously held on deposit that reduced cash flow by $345 million, and
- RG&E's $34 million payment to resolve a dispute with Niagara Mohawk Power Corporation. The payment was charged to a regulatory asset.

Those decreases in cash flow were partially offset by:

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

Investing Activities Cash Flows

: Net cash used in investing activities was $602 million in 2007 compared to $228 million in 2006 and $368 million in 2005. The $374 million increase in 2007 was primarily due to increased capital spending and to the increase in current investments available for sale with proceeds from issuances of our common stock. The $141 million decrease in 2006 was primarily due to the liquidation of current investments available for sale.

Utility capital spending totaled $444 million in 2007, $408 million in 2006 and $331 million in 2005. Capital spending in all three years was financed principally with internally generated funds, and was primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates, new customer care systems for NYSEG and RGE and transmission investments.

Utility capital spending is projected to be $660 million in 2008, about one-half of which is expected to be paid for with internally generated funds. The spending will be primarily for the same purposes described above, except for the customer care systems for NYSEG and RG&E, which have been completed. (See Item 8 - Note 8 to our Consolidated Financial Statements.)

Cash flows from investing activities include investment in and proceeds from the sale of auction rate securities, which are recorded as current investments available for sale. We have used auction rate securities in a manner similar to cash equivalents and the amount invested in such securities increased as short-term funds were available. We increased our investments in auction rate securities by $157 million during 2007, primarily with a share of the proceeds from issuances of our common stock.

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As a result of uncertainties in the auction rate securities markets, we have reduced our exposure to those investments. As of February 27, 2008, our investments in auction rate securities had declined to $25 million. Of that amount, $8 million had failed at auction and we are holding this amount until the next auction period. Of the $25 million, $23 million carried AAA ratings after giving effect to applicable bond insurance, and $16 million was issued by entities with underlying credit ratings of AA or better.

Financing Activities Cash Flows

: Net cash provided by financing activities was $94 million in 2007 compared to net cash used in financing activities of $177 million in 2006 and $128 million in 2005. The $272 million increase in 2007 was primarily due to our issuance of 10 million shares of common stock. The $50 million increase in 2006 was primarily due to the lower net issuance of long-term debt securities than in 2005.

Capital Structure at December 31,	2007	2006	2005
Long-term debt(1)	54.1%	57.1%	57.0%
Short-term debt(2)	1.9%	1.6%	1.7%
Preferred stock	0.3%	0.3%	0.4%
Common equity	43.7%	41.0%	40.9%
	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 and various medium-term and long-term debt transactions.

Our equity financing activities during 2007 and early 2008 included:

- Selling nine million shares of common stock at $24.25 per share on March 27, 2007. As provided for in our underwriting agreement, we sold an additional one million shares of common stock at $24.25 per share on April 2, 2007, pursuant to an overallotment provision. After deducting underwriting fees and other costs, the aggregate net proceeds were $235 million. We are using the proceeds to fund the repurchase of debt and for general corporate purposes, including our construction program. The sale increased our common equity ratio to approximately 44%.

- Raising our common stock dividend 3.3% in October 2007 to a new annual rate of $1.24 per share.
- Repurchasing 350,000 shares of our common stock in January 2007, primarily for grants of restricted stock.
- Awarding 343,971 shares of our common stock in 2007, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.94 per share of common stock.
- Issuing 406,073 shares of our common stock in 2007, at an average price of $24.87 per share, through our Investor Services Program. Pursuant to the Merger Agreement, effective June 30, 2007, shares purchased for the Investor Services Program are now purchased in the open market.
- Repurchasing 275,000 shares of our common stock in January 2008, primarily for grants of restricted stock.
- Awarding 334,505 shares of our common stock in February 2008, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a grant date fair value of $25.91 per share of common stock.

On July 18, 2007, RG&E filed a Form 15 with the SEC, and on July 24, 2007, the New York Stock Exchange filed a Form 25 with respect to RG&E's redeemed Series UU bonds, which terminated RG&E's status as a registrant under the Securities Exchange Act of 1934 (Exchange Act). RG&E no longer files Exchange Act reports including Forms 10-K, 10-Q and 8-K, and proxy statements or information statements

. We do not expect the termination of RG&E's Exchange Act registration will materially affect its access to or cost of capital.

In July 2007 RG&E issued $100 million of First Mortgage 6.47% Bonds, due 2032, Series WW, to fund a portion of the amount necessary to redeem $125 million of its First Mortgage 6.65% Bonds, due 2032, Series UU, which were redeemed on July 23, 2007.

In September 2007 CMP issued $40 million of Series F medium-term notes at 6.40%, due in 2037, of which $15 million was used to refinance maturing Series E medium-term notes at 4.25%, due in 2007, and the remainder was used for general corporate purposes.

In October 2007 SCG issued $40 million of medium-term notes at 6.38%, due in 2037, to refinance maturing Series II medium-term notes at 7.60% due in 2007.

In October 2007 CNG issued $20 million of medium-term notes at 6.66%, due in 2037, of which $19 million was used to refinance maturing Series B medium-term notes at 6.62% - 6.69% due in 2007. The remainder was used for general corporate purposes.

In December 2007 NYSEG issued $200 million of 6.15% notes, due in 2017, of which $150 million was used to refinance maturing 4 3/8% notes and $50 million was used to partially fund a contribution to an external VEBA trust required by the joint proposal approved by the NYPSC in September 2007.

Available Sources of Funding

Energy East is the sole borrower in a revolving credit facility providing maximum borrowings of up to $300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. In June 2007 we extended our two revolving credit facilities for one year. Both facilities now have expiration dates in 2012 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, 2007 and 2006.

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 $138 million of such short-term debt outstanding at December 31, 2007, and $109 million outstanding at December 31, 2006. The weighted-average interest rate on short-term debt was 5.1% at December 31, 2007 and 6.0% at December 31, 2006.

We filed an automatic shelf registration statement with the SEC in March 2007 and have the ability to issue, from time to time, an indeterminate amount of an unspecified combination of common stock, preferred stock, senior debt securities and junior subordinated debt securities.

Results of Operation

Earnings per Share

	2007	2006	2005
(Thousands, except per share amounts)			
Net Income	$251,298	$259,832	$256,833
Average Common Shares Outstanding, basic	154,801	146,962	146,964
Earnings per Share, basic	$1.62	$1.77	$1.75

Comparing 2007 to 2006

: Earnings per share, basic for 2007 decreased 15 cents compared to 2006. The major decreases in earnings per share were:

- 53 cents due to lower electric margins, excluding delivery volume increases, primarily as a result of NYSEG's August 2006 electric rate order,
- 9 cents due to an increase in average common shares outstanding primarily as a result of our issuance of 10 million shares in the spring of 2007,
- 8 cents resulting from the discontinuance of credits from NYSEG's internal OPEB reserve as a result of NYSEG's August 2006 rate order and the OPEB joint proposal settlement. (See Electric Delivery Business Developments, NYPSC Proceeding on NYSEG's Accounting for OPEB),
- 6 cents for costs related to the Merger, primarily investment banking and legal costs to obtain regulatory approval,
- 5 cents due to the effect of earnings sharing true-ups relating to 2005 for NYSEG and RG&E that increased earnings in 2006,
- 4 cents for the effect of environmental insurance settlements that increased earnings in the fourth quarter of 2006, and
- 4 cents due to increases in other operating and maintenance expense items.

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

- 14 cents resulting from lower income taxes, primarily due to adjustments to reflect the actual 2006 tax expense as filed and favorable variances in recurring flow-through items,
- 13 cents from lower interest costs due to lower carrying costs on regulatory liabilities, savings from debt refinancings and the reduction of debt using proceeds from our issuance of common stock in the spring of 2007,
- 13 cents in electric margins and 15 cents in natural gas margins due to higher electricity and natural gas delivery volumes,
- 11 cents from lower storm-related costs,
- 5 cents from lower bad debt expenses, and
- 4 cents for the recognition in July 2006 of unamortized expenses related to the retirement of our 8 1/4% debt securities and associated trust preferred securities.

Comparing 2006 to 2005

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

- 18 cents due to higher margins on electricity sales, primarily reflecting lower accruals under various earnings-sharing mechanisms,
- 7 cents from lower income tax expense reflecting variances in recurring flow-through items, differences between the 2005 filed tax return compared to the 2005 book tax expense and settlement of an audit of our 2002 and 2003 federal income tax returns,
- 4 cents resulting from environmental insurance settlements received in the fourth quarter of 2006,
- 5 cents due to the termination of SGF's operations in 2005, including 4 cents from the writedown of its assets, and
- 2 cents due to reductions in various operating and maintenance expenses.

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

- 11 cents resulting from higher storm and flood costs,
- 7 cents resulting from higher bad debt expense, including 4 cents for amounts that were previously deferred and that we began to recover as a result of SCG's rate increase effective January 1, 2006,
- 6 cents for higher interest expense due to higher rates on short-term and variable-rate debt, and higher carrying costs on regulatory liabilities,
- 5 cents for the recognition of unamortized expense as a result of the redemption of our 8 1/4% junior subordinated debt securities and associated trust preferred securities in July 2006,
- 4 cents for higher depreciation expense, due to placing NYSEG's customer care system into service in the first quarter of 2006, and
- 2 cents from lower margins on natural gas sales due to warmer weather. This amount would have been higher if not for SCG's rate increase effective January 1, 2006, and the effect of weather normalization mechanisms.

Energy Delivery

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

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

Percentage increases (decreases) in energy deliveries and electricity commodity sales compared to the prior year are:

	Electricity Deliveries		Natural Gas Deliveries	
	2007	2006	2007	2006
(Thousands)				
Residential	2%	(4%)	11%	(12%)
Commercial	4%	(2%)	7%	(11%)
Industrial	1%	(3%)	2%	(11%)
Other	3%	(2%)	3%	17%
Transportation of customer-owned natural gas	NA	NA	1%	(7%)
Total Retail	3%	(3%)	5%	(8%)
Wholesale	(22%)	(2%)	NM	(87%)
Total Deliveries	(3%)	(2%)	6%	(8%)
Electricity commodity sales	(1%)	(7%)	NA	NA

NA - not applicable, NM - not meaningful

Several factors influence the volume of energy deliveries, but the major factor is weather. Winter temperatures in 2007 were significantly colder than in 2006, but still warmer than normal. The effects of warmer or colder winter weather are especially significant for our natural gas

companies. We estimate that for 2007, one-fifth of the 3% increase in retail electricity deliveries and one-half of the 5% increase in retail natural gas deliveries was the result of colder winter weather. Weather conditions for New York and New England for the past three years are summarized below.

Weather Conditions

	2007	2006	2005	Normal
New York				
Heating-degree days	6,595	5,991	6,870	6,974
(Warmer) colder than prior year	10%	(13%)		
(Warmer) colder than normal	(5%)	(14%)		
Cooling-degree days	653	562	748	492
(Cooler) warmer than prior year	16%	(25%)		
(Cooler) warmer than normal	33%	14%		
New England				
Heating-degree days	6,145	5,447	6,229	6,315

(Warmer) colder than prior year	13%	(13%)		
(Warmer) colder than normal	(3%)	(14%)		
Cooling-degree days	409	444	506	388
(Cooler) warmer than prior year	(8%)	(12%)		
(Cooler) warmer than normal	5%	14%		

Operating Results for the Electric Delivery Business

	2007	2006	2005
(Thousands)			
Operating Revenues			
Retail	$2,271,680	$2,253,339	$2,250,105
Wholesale	465,804	554,500	568,746
Other	143,510	215,198	150,707
Total Operating Revenues	2,880,994	3,023,037	2,969,558
Operating Expenses			
Electricity purchased and fuel used in generation	1,441,000	1,467,068	1,457,746
Other operating and maintenance expenses	708,165	715,219	672,595
Depreciation and amortization	179,618	187,587	178,806
Other taxes	150,068	148,589	143,359
Total Operating Expenses	2,478,851	2,518,463	2,452,506
Operating Income	$402,143	$504,574	$517,052

Operating Revenues

: The $142 million decrease in operating revenues for 2007 was primarily the result of:

- A decrease of $89 million in wholesale revenues, reflecting a 22% decline in wholesale volume,
- A decrease of $37 million due to higher accruals for earnings sharing, which is included in other revenues. Those higher accruals reflect $14 million of adjustments recorded in 2006 after NYSEG and RG&E finalized their annual compliance filings for 2005,
- A decrease of $37 million due to lower NBC accruals, which will be passed on to customers through lower transition charges,
- A decrease of $36 million resulting from NYSEG's delivery rate decrease pursuant to its August 2006 rate order, and
- A decrease of $14 million for our New York utilities under the Voice Your Choice commodity programs where they provide supply, including $10 million as a result of lower retail prices and $4 million due to a 1% reduction in sales.

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Those decreases were partially offset by:

- An increase of $35 million resulting from a 3% increase in retail deliveries. Approximately one-fifth of the increase was due to colder winter temperatures in 2007,
- An increase of $33 million in average delivery prices, primarily the result of higher transition charges. Transition charges allow our electric utility companies to recover actual generation and purchased power costs

and have no net effect on earnings. The increase in transition charges was partially offset by the NBC accrual discussed above, and
- An increase of $2 million in other revenues.

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

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

Those increases were partially offset by:

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

<u>Operating Expenses</u>

: The $40 million decrease in operating expenses for 2007 was primarily the result of:

- A decrease of $29 million for storm-related costs,
- A decrease of $26 million for lower purchased power costs, including $10 million because of a major NUG contract that expired, and
- A decrease of $8 million in depreciation expense primarily due to lower depreciation rates adopted in NYSEG's August 2006 rate order.

Those decreases were partially offset by:

- An increase of $11 million in OPEB expenses attributable to the discontinuance of credits from the internal reserve as a result of NYSEG's August 2006 rate order,
- An increase of $8 million related to the OPEB joint proposal settlement (see Electric Delivery Business Developments - NYPSC Proceeding on NYSEG's Accounting for OPEB), and
- An increase of $5 million due to higher transmission expenses.

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

- An increase of $43 million in operating and maintenance costs, including $26 million for storm restoration, $9 million for a write-off resulting from NYSEG's August 2006 rate order and $9 million for higher bad debt expense,
- An increase of $9 million in purchased power costs resulting from a $39 million increase for higher wholesale electricity market prices, and $25 million for higher purchased power costs for RG&E related to Ginna purchases, partially offset by a $55 million decrease due to the expiration of a major NUG contract in 2006,
- An increase of $9 million in depreciation resulting largely from NYSEG's new customer care system, and
- An increase of $5 million in other taxes.

Operating Results for the Natural Gas Delivery Business

	2007	2006	2005
(Thousands)			
Operating Revenues			
Retail	$1,750,367	$1,676,527	$1,764,235
Wholesale	15,058	563	643
Other	6,364	20,511	18,669
Total Operating Revenues	1,771,789	1,697,601	1,783,547
Operating Expenses			
Natural gas purchased	1,116,092	1,079,980	1,161,059
Other operating and maintenance expenses	248,778	246,727	246,339
Depreciation and amortization	86,919	86,728	85,050
Other taxes	99,621	95,390	98,589
Total Operating Expenses	1,551,410	1,508,825	1,591,037
Operating Income	$220,379	$188,776	$192,510

Operating Revenues

: The $74 million increase in operating revenues for 2007 was primarily the result of:

- An increase of $123 million resulting from a 5% increase in retail deliveries, primarily due to colder winter weather in 2007,
- An increase of $16 million from higher base rates for CNG effective April 1, 2007,
- An increase of $14 million due to a new natural gas supply optimization agreement under which we manage our own gas supply, and
- An increase of $14 million in transportation revenues primarily as a result of more retail customers taking supply from other providers.

Those increases were partially offset by:

- A decrease of $67 million due to lower market prices for natural gas, which were passed on to customers,
- A decrease of $12 million from CNG's interruptible margin sharing mechanism,
- A decrease of $12 million as a result of lower weather normalization accruals, and
- A decrease of $2 million in other revenue.

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

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

That decrease was partially offset by:

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

Operating Expenses

: The $43 million increase in operating expenses for 2007 was primarily the result of:

- An increase of $94 million in natural gas purchases due to higher retail delivery volumes,
- An increase of $12 million in natural gas purchases due to an increase in wholesale sales,
- An increase of $10 million from increases in various operating and maintenance costs, including $6 million of regulatory deferrals and adjustments, and
- An increase of $4 million in gross receipts taxes as a result of higher revenues.

Those increases were partially offset by:

- A decrease of $70 million in natural gas purchases resulting from lower market prices that were passed on to customers, and
- A decrease of $11 million due to lower bad debt reserves, resulting largely from increased collection efforts.

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

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

Those decreases were partially offset by:

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

Operating Results for the Energy Marketing Business

The primary business included in our Other segment is our energy marketing business comprised of Energetix, Inc. and NYSEG Solutions, Inc., which market electricity and natural gas to customers throughout the state of New York. They currently have 182,000 electricity customers and 55,000 natural gas customers within the service territories of RG&E, NYSEG and several other New York state utilities.

	2007	2006	2005
(Thousands)			
Electricity sales (MWh)	4,497	4,516	5,025

Natural gas sales (Dth)	7,950	7,309	10,605
Operating Revenues			
Electric	$379,831	$316,221	$409,473
Natural gas	85,503	81,239	109,608
Total Operating Revenues	465,334	397,460	519,081
Operating Expenses			
Electricity purchased	360,613	300,053	397,251
Natural gas purchased	82,384	75,489	101,073
Other operating expenses	15,942	12,598	13,560
Total Operating Expenses	458,939	388,140	511,884
Operating Income	$6,395	$9,320	$7,197

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Operating Revenues

: The $68 million increase in operating revenues for 2007 was primarily the result of:

- An increase of $65 million due to higher retail electric revenues from variable and fixed rate customers that resulted from higher market prices for electricity, and
- An increase of $12 million from higher natural gas sales due to additional customers.

Those increases were partially offset by:

- A decrease of $8 million due to lower natural gas prices resulting in part from lower fixed rate gas prices, and
- A decrease of $1 million due to lower electric sales resulting from the loss of some large customers to other suppliers.

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

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

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

Operating Expenses

: The $71 million increase in operating expenses for 2007 was primarily the result of:

- An increase of $62 million in purchased electricity resulting from higher market prices,
- An increase of $12 million in purchased natural gas from higher natural gas sales as a result of additional customers, and
- An increase of $3 million in other operating expenses due to additional sales and marketing expenses and higher billing costs.

Those increases were partially offset by:

- A decrease of $5 million in natural gas purchased due to lower natural gas prices, and
- A decrease of $1 million in electricity purchased due to customer attrition.

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

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

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

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Other Items

	2007	2006	2005
(Thousands)			
Other (Income)	$(38,884)	$(46,126)	$(32,904)
Other Deductions	$11,483	$24,578	$8,858
Interest Charges, net	$275,938	$308,824	$288,897
Income Taxes	$114,058	$155,255	$169,997

Other (Income) and Other Deductions

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

Other (income) net of Other deductions, increased by $6 million in 2007. The changes include:

- An $11 million decrease in Other deductions from the recognition in 2006 of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and the associated trust preferred securities,
- A $3 million increase in interest income, primarily from the investment of a portion of the proceeds from our common stock issuances, and
- A $3 million increase in the Allowance for funds used during construction due to higher construction expenditures.

Those increases were partially offset by:

- An $8 million decrease in Other (income) due to the effect of environmental insurance settlements collected in 2006, and
- A $2 million income decrease related to risk management activity (gains net of losses).

The changes for 2006 include:

- An $11 million increase in Other deductions for the recognition of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and the associated trust preferred securities in July 2006,
- An $8 million increase in Other (income) from environmental insurance settlements,

- A $6 million increase in Other deductions from higher losses on risk management contracts, and
- A $4 million increase in Other (income) from higher gains on risk management activity.

Interest Charges, Net

: Interest charges, net decreased $33 million in 2007, primarily due to:

- Lower carrying costs on regulatory liabilities of $25 million,
- Savings from debt refinancings, and
- The repurchase of debt using some of the proceeds from our common stock issuances.

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

- Higher rates on short-term and variable-rate debt, and
- Higher carrying costs on regulatory liabilities of $7 million.

Income Taxes

: The effective tax rate was 31% in 2007, 37% in 2006, and 40% in 2005. The decrease in the 2007 effective tax rate was primarily due to variances in recurring flow-through items, including the flow-through effect of a book depreciation rate change for NYSEG that went into effect on January 1, 2007, and differences in the 2006 filed tax return compared to the 2006 booked tax expense, primarily due to a change related to the timing of the deductibility of property tax expense for RG&E. The decrease in the 2006 effective tax rate was primarily due to variances in recurring flow-through items, differences in the 2005 filed tax return compared to the 2005 booked tax expense and settlement of an audit of our 2002 and 2003 federal income tax returns. The effective tax rate in prior years is not necessarily indicative of what the effective tax rate will be in future years.

Pension Income

: Periodic pension income is included in other operating and maintenance expenses and reduces the amount of expense that would otherwise be reported. Pension income for 2007 increased $17 million, primarily due to a higher-than-expected return on plan assets, resulting from increased plan assets, and lower amortization of actuarial losses. Pension income for 2006 was the same as in 2005.

	2007	2006	2005
($ in Millions)			
Periodic pension income (pretax)	$47	$30	$30
As a percent of net income	11%	7%	7%

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

We estimate pension income of $57 million for 2008 and expect to contribute $1 million to our pension benefit plans and approximately $60 million to our other postretirement benefit plans in 2008. (See Item 8 - Note 13 to our Consolidated Financial Statements.)

Item 7A. Quantitative and Qualitative Disclosures About 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, 2007, a 1% change in average interest rates would change our annual interest expense for variable-rate debt by about $8 million, including the effects on auction rate debt discussed below. As required by DIG Issue G26 we dedesignated the hedging relationships as of April 1, 2007, for NYSEG's two cash flow hedges related to its auction rate notes. (See Item 8 - Notes 1, 5, 6 and 10 to our Consolidated 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.

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NYSEG and RG&E have issued $776 million of tax-exempt pollution control notes, $518 million of which have rates that are reset periodically through an auction process that occurs every 7 days for $416 million and every 35 days for the remaining $102 million. The principal and interest on these notes are insured by either XL Capital Assurance, Inc. (XLCA), Ambac Assurance Corporation (Ambac), or MBIA Insurance Corporation (MBIA). The investors' source of liquidity on these notes is the auction market itself. As the financial strength of bond insurers has been called into question, due in part to their exposure to rising mortgage default rates, investors have reacted by withdrawing from the market, thereby significantly reducing market liquidity and resulting in higher and more volatile interest rates. More recently, as the market became illiquid and broker-dealers withdrew their capital support, an increasing percentage of the auctions, including NYSEG and RG&E auctions, have failed to receive sufficient bids to set new interest rates. In such instances, the issuer is obligated to pay a formulaic failure rate until sufficient bids are received at a scheduled auction. For NYSEG and RG&E, the interest rates resulting from failed auctions are a function of current short-term money market rates multiplied by a factor, ranging from 175% to 300%, based on the rating of the applicable bond insurer. To date, failed auction rates for NYSEG and RG&E have ranged from 3.3% to 10.5%. These rates are significantly higher than rates paid in previous auctions. Continued and prolonged illiquidity in the auction rate market could significantly increase our interest costs. The weighted-average maximum rate if all issues were to fail at auction could be approximately 7%, which would result in higher interest costs of approximately $1 million per month for NYSEG and $0.5 million per month for RG&E over 2006 levels. Pursuant to its current rate plans, RG&E defers any changes in variable rate interest expense, significantly reducing its exposure. As of February 27, 2008, we were paying formulaic failure rates on $455 million of auction rate debt. The weighted-average interest rate on all $518 million of auction rate securities was 5.6%.

We are currently investigating our options in order to reduce our exposure to the auction market. All of our auction rate pollution control notes are multi-modal, and thus can be converted into a range of floating or fixed rate securities, including variable-rate demand notes, term put bonds or fixed-rate bonds, with or without call provisions. Our ability to convert into other interest rate modes may require that we temporarily reacquire the outstanding notes or obtain a liquidity facility. There can be no assurance regarding our ability to effect conversions on a timely or cost-effective basis.

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 the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it.

NYSEG and RG&E currently offer their retail customers choice in their electricity supply including a fixed rate option, a variable rate option under which rates vary monthly based on the actual cost of electricity purchases and an option to purchase electricity supply from an ESCO. Both NYSEG's and RG&E's customers make their supply choice annually. Those customers who do not make a choice are served under a variable or default price option. Customers also pay an NBC, which includes recovery of stranded costs. The table below shows the percentages of load served under the various commodity supply options in 2007 and the projections for 2008.

		NYSEG		RG&E
	2008	2007	2008	2007
Fixed Price Option	12%	17%	18%	21%
Variable Price Option or Default Supply Option	49%	45%	33%	29%
Energy Service Company Option	39%	38%	49%	50%

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

As of February 15, 2008, the expected load for NYSEG's fixed rate option customers is 84% hedged for on-peak and off-peak periods in 2008. A fluctuation of $1.00 per MWh in the average price of electricity would change NYSEG's earnings less than $260,000 in 2008. RG&E expects to meet its fixed price load obligations in 2008 with owned generation or long-term supply contracts. The estimated percentage of NYSEG's hedged load and RG&E's expectation that it can meet load requirements with current resources are 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 forecasts.

Other comprehensive income associated with our financial electricity contracts for the year ended December 31, 2007, was $23 million, reflecting an increase of $16 million as compared to December 31, 2006. The increase is primarily a result of wholesale market price changes for electricity and the settlement of positions in 2007. Other comprehensive income for 2007 will have no effect on future net income because it reflects financial electricity contracts to hedge the price of our electric load requirements for customers who have chosen a fixed price option.

All of our natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities.

Energetix and NYSEG Solutions offer retail electric and natural gas service to customers in New York state and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of February 15, 2008, the energy marketing subsidiaries' expected fixed price loads were 92% hedged for 2008. A fluctuation of $1.00 per MWh in the average price of electricity would change earnings less than $190,000 in 2008. The percentage of hedged load for the energy marketing subsidiaries is based on load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

NYSEG, RG&E, Energetix and NYSEG Solutions face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or S&P). 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 $7 million if our expected return on plan assets were to change by 1/4% and by approximately $6 million if our discount rate were to change by 1/4%. Under RG&E's Electric and Natural Gas Rate Agreements and under NYSEG's natural gas rate plan, we defer changes in pension income resulting from changes in market conditions. (See Item 8 - Note 13 to our Consolidated Financial Statements.)

We had investments in auction rate securities of $177 million at December 31, 2007. Those securities earn interest at rates established at periodic auctions, typically every 7 or 35 days. We record our investments in those securities at cost, which approximates fair market value, due to their variable interest rates. As a result of uncertainties in the auction rate securities markets, we have reduced our exposure to those investments. As of February 27, 2008, our investments in auction rate securities had declined to $25 million. Of that amount, $8 million had failed at auction and we are holding this amount until the next auction period. Of the $25 million, $23 million carried AAA ratings after giving effect to applicable bond insurance, and $16 million was issued by entities with underlying credit ratings of AA or better.

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Item 8. Financial Statements and Supplementary Data

Energy East Corporation
Consolidated Statements of Income

Year Ended December 31,	2007	2006	2005
(Thousands, except per share amounts)			
Operating Revenues			
	$4,652,783	$4,720,638	$4,753,105
Utility			
Other	525,325	510,027	545,438
Total Operating Revenues	5,178,108	5,230,665	5,298,543
Operating Expenses			
Electricity purchased and fuel used in generation			
Utility	1,441,000	1,467,068	1,457,746
Other	363,793	353,402	360,621
Natural gas purchased			
Utility	1,116,092	1,079,980	1,161,059
Other	90,418	79,472	107,755
Other operating expenses	842,996	796,350	797,015
Maintenance	175,618	218,499	197,704
Depreciation and amortization	277,490	282,568	277,217
Other taxes	255,680	249,834	246,271
Total Operating Expenses	4,563,087	4,527,173	4,605,388
Operating Income	615,021	703,492	693,155
Other (Income)	(38,884)	(46,126)	(32,904)
Other Deductions	11,483	24,578	8,858
Interest Charges, Net	275,938	308,824	288,897
Preferred Stock Dividends of Subsidiaries	1,128	1,129	1,474
Income Before Income Taxes	365,356	415,087	426,830
Income Taxes	114,058	155,255	169,997
Net Income	$251,298	$259,832	$256,833
Earnings per Share, basic	$1.62	$1.77	$1.75
Earnings per Share, diluted	$1.61	$1.76	$1.74
Average Common Shares Outstanding, basic	154,801	146,962	146,964
Average Common Shares Outstanding, diluted	155,805	147,717	147,474

The

notes on pages II-54 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31,	2007	2006
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$97,066	$93,373
Investments available for sale	177,045	20,000
Accounts receivable and unbilled revenues, net	990,255	914,657
Fuel and natural gas in storage, at average cost	258,172	277,766
Materials and supplies, at average cost	28,722	33,273
Deferred income taxes	38,383	93,187
Derivative assets	23,959	1,327
Prepayments and other current assets	132,991	193,226
Total Current Assets	1,746,593	1,626,809
Utility Plant, at Original Cost		
Electric	5,787,362	5,557,858
Natural gas	2,708,612	2,654,426
Common	583,657	550,440
	9,079,631	8,762,724
Less accumulated depreciation	3,086,765	2,935,798
Net Utility Plant in Service	5,992,866	5,826,926
Construction work in progress	165,628	121,097
Total Utility Plant	6,158,494	5,948,023
Other Property and Investments	172,993	183,315
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	190,367	263,659
Unfunded future income taxes	338,749	256,683
Environmental remediation costs	185,773	128,925
Unamortized loss on debt reacquisitions	48,819	52,724
Nonutility generator termination agreements	64,744	79,241
Natural gas hedges	11,154	47,372
Pension and other postretirement benefits	259,554	351,011
Other	346,079	356,299
Total regulatory assets	1,445,239	1,535,914
Other assets		
Goodwill	1,526,048	1,526,048
Prepaid pension benefits	698,432	577,356

Derivative assets	17,450	46,375
Other	113,460	118,561
Total other assets	2,355,390	2,268,340
Total Regulatory and Other Assets	3,800,629	3,804,254
Total Assets	$11,878,709	$11,562,401

The

notes on pages II-54 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31,	2007	2006
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$99,914	$260,768
Notes payable	137,717	109,363
Accounts payable and accrued liabilities	484,963	470,325
Interest accrued	58,681	57,243
Taxes accrued	77,276	44,009
Unfunded future income tax	-	19,664
Derivative liabilities	11,491	71,678
Customer refund	-	70,770
Other	251,239	209,839
Total Current Liabilities	1,121,281	1,313,659
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	892,333	843,273
Deferred income taxes	5,088	105,528
Gain on sale of generation assets	99,514	127,674
Pension benefits	124,300	127,330
Natural gas hedges	1,544	-
Other	165,869	93,268
Total regulatory liabilities	1,288,648	1,297,073
Other liabilities		
Deferred income taxes	1,322,738	1,105,117
Nuclear plant obligations	157,376	202,963
Pension and other postretirement benefits	451,642	530,838

Environmental remediation costs	158,629	168,949
Derivative liability	21,318	21,871
Other	248,368	306,283
Total other liabilities	2,360,071	2,336,021
Total Regulatory and Other Liabilities	3,648,719	3,633,094
Long-term debt	3,877,029	3,726,709
Total Liabilities	8,647,029	8,673,462
Commitments and Contingencies		
Preferred Stock of Subsidiaries		
Redeemable solely at the option of subsidiaries	24,587	24,592
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 158,279 shares outstanding at December 31, 2007, and 147,907 shares outstanding at December 31, 2006)	1,583	1,480
Capital in excess of par value	1,752,465	1,505,795
Retained earnings	1,447,889	1,382,461
Accumulated other comprehensive income (loss)	7,609	(23,779)
Treasury stock, at cost (86 shares at December 31, 2007, and 52 shares at December 31, 2006)	(2,453)	(1,610)
Total Common Stock Equity	3,207,093	2,864,347
Total Liabilities and Stockholders' Equity	$11,878,709	$11,562,401

The

notes on pages II-54 through II-83 are an integral part of our consolidated financial statements.

Energy East Corporation
Consolidated Statements of Cash Flows

Year Ended December 31,	2007	2006	2005
(Thousands)			
Operating Activities			
Net income	$251,298	$259,832	$256,833
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	386,850	418,152	382,873
Income taxes and investment tax credits deferred, net	107,443	31,125	69,729
Pension income	(47,355)	(30,081)	(29,967)
Changes in current operating assets and liabilities			
Accounts receivable and unbilled revenues, net	(164,649)	16,026	(107,308)
Inventory	24,507	1,437	(86,735)

Prepayments and other current assets	61,553	(65,466)	(36,373)
Accounts payable and accrued liabilities	25,029	(141,529)	203,392
Taxes accrued	15,002	11,148	1,376
Interest accrued	1,438	10,721	3,053
Customer refund	(10,056)	(15,485)	(25,329)
Other current liabilities	(14,540)	(15,767)	11,448
Pension and OPEB contributions	(66,000)	(400)	(54,320)
Changes in other assets			
RG&E nuclear plant dispute settlement	-	(33,655)	(125)
Other	(48,669)	(1,722)	(76,167)
Changes in other liabilities			
ASGA charges	(41,008)	(59,443)	(45,406)
Other	30,357	(6,407)	37,758
Net Cash Provided by Operating Activities	511,200	378,486	504,732
Investing Activities			
Utility plant additions	(444,009)	(408,231)	(331,294)
Other property additions	(2,570)	(3,817)	(2,507)
Other property sold	19	342	25,704
Maturities of current investments available for sale	1,007,850	1,054,665	1,635,005
Purchases of current investments available for sale	(1,164,895)	(881,740)	(1,692,275)
Investments	1,771	11,022	(3,064)
Net Cash Used in Investing Activities	(601,834)	(227,759)	(368,431)
Financing Activities			
Issuance of common stock	234,980	343	2,654
Repurchase of common stock	(8,339)	(6,107)	(6,492)
Issuance of first mortgage bonds	139,890	-	70,000
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	(190,006)	(39)	(47,260)
Derivative activity	-	22,899	-
Long-term note issuances	259,758	652,137	208,893
Long-term note repayments	(192,221)	(667,263)	(120,061)
Notes payable three months or less, net	28,756	(12,873)	(85,967)
Notes payable issuances	2,654	1,436	1,251
Notes payable repayments	(3,055)	(547)	(408)
Dividends on common stock	(178,090)	(167,349)	(150,367)
Net Cash Provided by (Used In) Financing Activities	94,327	(177,363)	(127,757)
Net Increase (Decrease) in Cash and Cash Equivalents	3,693	(26,636)	8,544
Cash and Cash Equivalents, Beginning of Year	93,373	120,009	111,465
Cash and Cash Equivalents, End of Year	$97,066	$93,373	$120,009

The

notes on pages II-54 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, 2005	147,118	$1,472	$1,477,518	$1,201,533	$(43,561)	$(5,020)	$(683)	$2,631,259
Net income				256,833				256,833
Other comprehensive income, net of tax					132,646			132,646
Comprehensive income								389,479
Common stock dividends declared ($1.115 per share)				(163,786)				(163,786)
Common stock issued - Investor Services Program	607	6	16,066					16,072
Common stock repurchased	(250)						(6,492)	(6,492)
Common stock issued - restricted stock plan	265		(6,404)			(451)	6,855	-
Amortization of deferred compensation under restricted stock plan						5,471		5,471
Treasury stock transactions, net	(39)		1,702				(1,405)	297
Amortization of capital stock issue expense, net			374					374
Balance, December 31, 2005	147,701	1,478	1,489,256	1,294,580	89,085	-	(1,725)	2,872,674

Net income				259,832				259,832
Other comprehensive income, net of tax					(113,502)			(113,502)
Comprehensive income								146,330
Adjustment to initially apply Statement 158					638			638
Common stock dividends declared ($1.17 per share)				(171,951)				(171,951)
Common stock issued - Investor Services Program	204	2	4,943					4,945
Common stock repurchased	(250)						(6,107)	(6,107)
Common stock issued - restricted stock plan	274		(6,722)				6,722	-
Amortization of restricted stock plan grants			8,458					8,458
Treasury stock transactions, net	(22)		(2)				(500)	(502)
Amortization of capital stock issue expense, net			9,862					9,862
Balance, December 31, 2006	147,907	1,480	1,505,795	1,382,461	(23,779)	-	(1,610)	2,864,347
Net income				251,298				251,298
Other comprehensive income, net of tax					31,388			31,388
Comprehensive income								282,686
Adjustment to initially apply FIN 48				1,291				1,291
Common stock dividends declared ($1.21 per share)				(187,161)				(187,161)
	10,000	100	242,400					242,500

Common stock issued - public offering								
Common stock issued - Investor Services Program	406	3	10,094					10,097
Common stock repurchased	(350)						(8,387)	(8,387)
Common stock issued - restricted stock plan	344		(8,273)				8,273	-
Amortization of restricted stock plan grants			9,943					9,943
Treasury stock transactions, net	(28)		27				(729)	(702)
Capital stock issue expense			(7,521)					(7,521)
Balance, December 31, 2007	158,279	$1,583	$1,752,465	$1,447,889	$7,609	-	$(2,453)	$3,207,093

The

notes on pages II-54 through II-83 are an integral part of our consolidated financial statements.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background:

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

Accounts receivable

: Accounts receivable at December 31 include unbilled revenues of $273 million for 2007 and $221 million for 2006, and are shown net of an allowance for doubtful accounts at December 31 of $51 million for 2007 and $59 million for 2006. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $68 million in 2007, $81 million in 2006 and $66 million in 2005.

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

The allowance for doubtful accounts is our best estimate of the amount of probable credit

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

Asset retirement obligations

: We record the fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO 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 regulated utilities defer any timing differences between rate recovery and depreciation expense as either a regulatory asset or a regulatory liability.

The term conditional ARO 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. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was $50 million for 2007 and $57 million for 2006. The ARO primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with our AROs are generation property, gas storage property, distribution property and other property.

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The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2007 and 2006. The decrease in 2007 primarily relates to a re-evaluation of abatement costs for the Beebee generating station and the increase in 2006 is primarily related to removal of asbestos from generating stations.

Year ended December 31,	2007	2006
(Thousands)		
ARO, beginning of year	$57,253	$29,895
Liabilities incurred during the year	(1,132)	21,025
Liabilities settled during the year	(1,486)	(1,435)
Accretion expense	1,949	1,538
Revisions in estimated cash flows	(6,914)	6,230
ARO, end of year	$49,670	$57,253

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

Our regulated utilities meet the requirements of Statement 71 and recognize a regulatory liability, for financial reporting purposes only, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Basic and diluted earnings per share

: We determine basic EPS by dividing net income by the weighted-average number of shares of common stock outstanding during the period. The weighted-average common shares outstanding for diluted EPS include the incremental effect of restricted stock and stock options issued and exclude stock options issued in tandem with SARs. Historically, we have issued stock options in tandem with SARs and substantially all stock option plan participants have exercised the SARs instead of the stock options. The numerator we use in calculating both basic and diluted EPS for each period is our reported net income.

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

Year Ended December 31,	2007	2006	2005
(Thousands)			
Basic average common shares outstanding	154,801	146,962	146,964
Restricted stock awards	1,004	755	510
Potentially dilutive common shares	171	131	343
Options issued with SARs	(171)	(131)	(343)
Dilutive average common shares outstanding	155,805	147,717	147,474

We exclude from the determination of EPS options that have an exercise price that is greater than the average market price of the common shares during the year. Shares excluded from the EPS calculation were: 2.0 million in 2007, 2.3 million in 2006 and 0.4 million in 2005. (See Note 11 for additional information concerning share-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	2007	2006	2005
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	$245,167	$249,662	$247,434
Income taxes, net of benefits received	$(12,377)	$93,294	$102,647

Interest capitalized was $4 million in 2007, $2 million in 2006 and $1 million in 2005.

Depreciation and amortization

: We determine depreciation expense substantially using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property - 56 years, distribution property - 50 years, generation property - 47 years, gas production property - 31 years, gas storage property - 25 years, and other property - 28 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 less than 1 year for its coal station to 31 years for its hydroelectric stations. Our depreciation accruals were equivalent to 3.0% of average depreciable property for 2007, 3.1% for 2006 and 3.3% for 2005.

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.

DIG Issue G26

: In December 2006 the FASB cleared DIG Issue G26, which provides guidance concerning a cash flow hedge of a variable-rate financial asset or liability for which the interest rate risk is not based solely on an index, such as an interest rate that is reset through an auction process. According to DIG Issue G26, an entity may designate the risk being hedged as the risk of overall changes in the hedged cash flows related to a variable-rate financial asset or liability. However, it may not designate the risk being hedged as the interest rate risk (the risk of changes in cash flows attributable to changes in the designated benchmark interest rate) unless the cash flows of the hedged transaction are explicitly based on that same benchmark interest rate. The implementation guidance of DIG Issue G26 became effective on April 1, 2007. As a result of applying DIG Issue G26, we dedesignated the hedging relationships as of April 1, 2007, for two of NYSEG's cash flow hedges and subsequently settled the contracts. A $3.3 million pretax loss incurred in the settlement of those derivatives and related to the period prior to April 1, 2007, will remain in accumulated other comprehensive income and be reclassified into earnings in the same periods that the hedged forecasted transactions have an effect on earnings.

Dividend restrictions

: Until consummation (or termination) of the Merger, we are prohibited from declaring and paying dividends in excess of the current rate of $.31 per share per quarter. We have no significant other restrictions that limit our payment of dividends.

EITF 06-10

: The FASB ratified the consensus in EITF 06-10 in late March 2007. EITF 06-10 requires an employer to recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement (in which the employee, versus the employer, owns and controls the insurance policy) in accordance with either Statement No. 106, or APB Opinion No. 12, *Omnibus Opinion - 1967* (Opinion 12). An entity would recognize a liability in

accordance with Statement 106 if, in substance, a postretirement benefit plan exists or in accordance with Opinion 12 if the arrangement is, in substance, an individual deferred compensation contract. EITF 06-10 also requires an employer to recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 is effective for fiscal years beginning after December 15, 2007, including interim periods within those fiscal years, with earlier application permitted. Entities should recognize the effects of applying the consensus through either (1) a change in accounting principle through a cumulative-effect adjustment to retained earnings as of the beginning of the year of adoption or (2) a change in accounting principle through retrospective application to all prior periods. We will apply the consensus in EITF 06-10 as of January 1, 2008, as a change in accounting principle through a cumulative-effect adjustment to retained earnings. The application of EITF 06-10 will not materially affect our results of operation, financial position or cash flows.

Estimates

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

FIN 48

: The FASB released FIN 48 in July 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with Statement 109 by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or to be taken in a tax return. The evaluation of a tax position is a two-step process. The first step is for an entity to determine if it is more likely than not that a tax position will be sustained upon examination. The second step involves measuring the amount of tax benefit to be recognized in the financial statements based on the largest amount of benefit that meets the prescribed recognition threshold. The difference between the amounts based on that position and the position taken in a tax return is generally recorded as a liability.

FIN 48 also provides guidance for the presentation of reserves in the balance sheet and the proper measurement of deferred tax assets and liabilities using the FIN 48 standard. That guidance requires reserves that are expected to be addressed in the next 12-month period to be classified as current. It also requires that the tax bases of assets and liabilities reflect the presumed FIN 48 outcome versus the actual filing position in determining the proper level of accumulated deferred income taxes in accordance with Statement 109.

We adopted FIN 48 effective January 1, 2007. The total gross unrecognized tax benefits at the date of adoption were $26.6 million and included income taxes of $21.2 million, interest of $5.2 million and a penalty of $0.2 million. The total gross unrecognized tax benefits as of December 31, 2007 were $23.5 million and includes income taxes of $18.0 million, interest of $5.3 million and a penalty of $.0.2 million. Including interest and penalty, $12.5 million of the gross unrecognized tax benefits would affect the effective tax rate, if recognized. The $3.2 million decrease in the gross income tax reserve, which is reconciled in the table below, is due primarily to a re-determination of reserves related to 2006, based on our filing of various 2006 income tax returns. The cumulative effect of adoption was an increase to retained earnings of $1.3 million. In addition, we reclassified $2.3 million of accumulated deferred income tax liabilities.

We have been audited through 2000 for New York state income taxes, through 2001 for federal income taxes and through 2002 for Maine income taxes. The statutes of limitation in Connecticut, Massachusetts and New Hampshire have expired for all years through 2003. Our New York state returns for 2001 through 2004, federal returns for 2002 through 2005 and Maine returns for 2003 and 2004 are currently under review. We anticipate that the reviews will be completed within the next 12 months. Approximately $10 million of the $18 million gross income tax reserve relates to the years currently under audit, with the majority relating to combined state reporting issues. We cannot estimate the ultimate outcome of the reviews.

Reconciliation of Changes in Gross Unrecognized Tax Benefits	2007
(Thousands)	
Balance as of January 1	$21,220
Increases for tax positions related to prior years	1,262
Reductions for tax positions related to prior years	(2,875)
Decreases for positions related to settlements with taxing authority	(1,616)
Balance as of December 31	$17,991

We continue to classify all interest and penalties related to uncertain tax positions as income tax expense.

New York State Income Tax Legislation

: On April 9, 2007, New York state enacted its 2007-2008 budget, which included amendments to the New York state income tax. Those amendments include a reduction in the corporate net income tax rate to 7.1% from 7.5%, and the adoption of a single sales factor for apportioning taxable income to New York state. Both amendments are effective January 1, 2007.

We have determined that these amendments did not have a material effect on our results of operation, financial position or cash flows.

Also included in the 2007-2008 New York state budget was a provision whereby certain corporations would be required to file unitary income tax returns. This provision became effective January 1, 2007. On June 25, 2007 New York state issued a Technical Service Bulletin providing further guidance as to what meets the unitary income tax filing criteria.

While we continue to monitor this issue, we have currently determined that we do not meet the unitary income tax filing criteria based on our review of the legislation, the June 25, 2007 Technical Service Bulletin and other public statements made by New York State Department of Taxation and Finance representatives.

FSP FIN 39-1

: The FASB issued FSP FIN 39-1 in late April 2007. FSP FIN 39-1 permits a reporting entity that is party to a master netting arrangement to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39). FSP FIN 39-1 also amends FIN 39 to replace the terms *conditional contracts* and *exchange contracts* with the term *derivative instruments* as defined in Statement 133. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying FSP FIN 39-1 are to be recognized as a change in accounting principle through retrospective application for all financial statements presented unless it is impracticable to do so. Upon application of FSP FIN 39-1, a reporting entity would be allowed to change its accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting arrangements. We elected early application of FSP FIN

39-1 beginning in the fourth quarter of 2007, with no effect on our results of operation, financial position or cash flows. We did not change our accounting policy and will continue to not offset fair value amounts recognized for derivative instruments under master netting arrangements.

Goodwill

: We record the excess of the cost over the fair value of net assets of purchased businesses as goodwill. We evaluate the carrying value of goodwill for impairment at least annually and on an interim basis if there are indications that goodwill might be impaired. We may recognize an impairment if the fair value of goodwill is less than its carrying value. (See Note 3.)

Investments available for sale - current

: We held current investments of $177 million at December 31, 2007, and $20 million at December 31, 2006, which consisted of auction rate securities classified as available for sale. We record our investments in those securities 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 generally been able to liquidate such securities during the scheduled auctions, including all investments held at December 31, 2007. As a result, we have had no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from our current investments. All income generated from our current investments is recorded as interest income.

As a result of uncertainties in the auction rate securities markets, we have reduced our exposure to those investments. As of February 27, 2008, our investments in auction rate securities had declined to $25 million. Of that amount, $8 million had failed at auction and we are holding this amount until the next auction period. Of the $25 million, $23 million carried AAA ratings after giving effect to applicable bond insurance, and $16 million was issued by entities with underlying credit ratings of AA or better.

Other (Income) and Other Deductions

:

Year Ended December 31,	2007	2006	2005
(Thousands)			
Interest and dividend income	$(19,623)	$(16,699)	$(15,802)
Allowance for funds used during construction	(5,057)	(2,266)	(1,552)
Gains on energy risk contracts	(2,731)	(6,158)	(2,701)
Earnings from equity investments	(3,499)	(3,483)	(3,959)
Environmental recovery	-	(8,383)	-
Miscellaneous	(7,974)	(9,137)	(8,890)
Total other (income)	$(38,884)	$(46,126)	$(32,904)
Losses from disposition of nonutility property	$122	$916	$100
Losses on energy risk contracts	4,495	6,376	40
Recognition of expense resulting from retirement of debt and trust preferred securities	-	11,248	-

Civic donations	2,766	3,363	3,744
Merger-enabled gas supply savings	-	(851)	796
Miscellaneous	4,100	3,526	4,178
Total other deductions	$11,483	$24,578	$8,858

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 2007 presentation. Effective January 1, 2007, we recognize book overdrafts where no credit is required to be extended by a bank as an operating activity rather than as a financing activity. As a result, our net cash provided by operating activities and net cash used in financing activities decreased $1 million for 2006. Effective April 1, 2007, we began recording unrecognized gains and losses on settled treasury hedges in other comprehensive income rather than as other assets or long-term debt. As a result, our other comprehensive income increased $10 million in 2007.

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Regulatory assets and liabilities

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

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each operating utility's current rate plans. In 2007 amortization of total regulatory assets net of amortization of total regulatory liabilities was $74 million.

Other regulatory assets and liabilities consisted of:

December 31,	2007	2006
(Thousands)		
Statement 106	$44,898	$51,819
Customer Hardship Arrearage Forgiveness and related programs	44,960	43,949
Loss on sale of RG&E Oswego generating unit	35,419	41,895
Asset retirement obligation	24,842	30,808
Deferred storm costs	42,307	28,811
Deferred pension costs	31,760	25,562
Stranded cost reconciliation	8,126	24,349
Deferred natural gas costs	41,129	21,087

RG&E merger costs	-	12,406
Other	72,638	75,613
Total other regulatory assets	$346,079	$356,299
Deferred natural gas costs	$14,187	$20,567
Asset retirement obligation	9,248	3,201
Nonfirm margin sharing	18,983	-
Economic development	3,855	7,205
Pension	16,709	6,527
Nuclear decommissioning	14,439	5,729
Overcollection of Gross Receipts Tax	-	5,506
Accrued earnings sharing	16,957	4,585
Other	71,491	39,948
Total other regulatory liabilities	$165,869	$93,268

Revenue recognition

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

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

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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. NYSEG and RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

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 those 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, Energetix and NYSEG Solutions face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or S&P). 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 have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we do not offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. Our obligation to return cash collateral under master netting arrangements was $7 million at December 31, 2007, and $5 million at December 31, 2006.

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.

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. NYSEG and RG&E 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 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 current and noncurrent derivative 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.

As of December 31, 2007, the maximum length of time over which we had hedged our exposure to the variability in future cash flows for forecasted energy transactions was 24 months. We estimate that gains of $17 million will be reclassified from accumulated other comprehensive income into earnings during 2008, as the underlying transactions occur.

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

Statement 123(R)

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

Statement 123(R) also requires a public entity to initially measure the cost of employee services received in exchange for an award of liability instruments (e.g., instruments that are settled in cash) based on the award's current fair value, subsequently remeasure the fair value of the award at each reporting date through the settlement date and recognize changes in fair value during the required service period as compensation cost over that period. We early adopted Statement 123(R) effective October 1, 2005, using the modified version of prospective application. Our adoption of Statement 123(R) did not have a material effect on our financial position, results of operation or cash flows. We describe our share-based compensation plans more fully in Note 11.

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

Our restricted stock awards have a retirement eligibility provision. Effective with our adoption of Statement 123(R) we follow the nonsubstantive vesting period approach, according to which an award is considered to be vested for expense recognition purposes when an employee's retention of the award is no longer contingent on providing subsequent service. Therefore, we recognize compensation cost immediately for any new awards of restricted stock to employees who are eligible for retirement on the date of the grant. We follow the nominal vesting period approach for any restricted stock awards granted prior to our adoption of Statement 123(R) and record compensation expense over the estimated vesting period for those restricted stock awards, beginning on the grant date. If an employee retires before the end of the estimated vesting period, we recognize at the date of retirement any remaining unrecognized compensation cost related to that employee's restricted stock. Our pro forma compensation cost for restricted

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stock for 2007, 2006 and 2005 following the nonsubstantive vesting period approach is not materially different from the compensation cost we recognized following the nominal vesting period approach.

Statement 141(R) and Statement 160

: In December 2007 the FASB issued Statement 141(R) and Statement 160, both the result of a joint project between the FASB and the International Accounting Standards Board, which published its comparable revised standards in January 2008 (International Financial Reporting Standard 3 (Revised 2007), *Business Combinations* and International Accounting Standard 27 (Revised 2007), *Consolidated and Separate Financial Statements*). The objective of Statement 141(R) is "to improve the relevance, representational faithfulness, and comparability of information that a reporting entity provides in its financial reports about a business combination and its effects." Some key changes that will result from the application of Statement 141(R) are: all transaction costs and most restructuring costs will be expensed, acquired in-process research and development costs will not be expensed at acquisition, and equity securities issued as part of the purchase price will be measured on the closing date instead of the announcement date. Statement 141(R) will apply to business combinations for which the acquisition date is on or after the beginning of an entity's first annual reporting beginning on or after December 15, 2008 (Energy East's annual reporting period beginning January 1, 2009), may not be applied before that date and must be applied prospectively. Statement 160 is intended "to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements" about noncontrolling (sometimes called minority) interests. Minority interest earnings will no longer be excluded from net income as a result of applying Statement 160. Statement 160 is effective for fiscal years (including interim periods) beginning on or after December 15, 2008 (January 1, 2009, for Energy East), with earlier adoption prohibited and prospective application required, except that the presentation and disclosure requirements are to be applied retrospectively. We expect that our application of both Statements will not materially affect our results of operation, financial position or cash flows.

Statement 157

: In September 2006 the FASB issued Statement 157. Changes from current practice that will result from the application of Statement 157 relate to the definition of fair value, the methods used to measure fair value, and expanded disclosures about fair value measurements. FAS 157 applies under other accounting pronouncements that require or permit fair value measurements in which the FASB previously concluded that fair value is the relevant measurement attribute, but does not require any new fair value measurements. We adopted Statement 157 effective January 1, 2008. Our adoption did not significantly affect our financial position and had no effect on our results of operation and cash flows.

Statement 158

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

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

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

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

We initially applied the recognition and disclosure provisions of Statement 158 as of December 31, 2006, which increased assets and liabilities, but had no effect on our results of operation or cash flows. Retrospective application of the recognition provisions and measurement provisions is not permitted. We measure our pension and other postretirement plan assets and benefit obligations as of the date of our fiscal year-end balance sheet and therefore have no need to change our measurement date.

Statement 159

: In February 2007 the FASB issued Statement 159, which will allow an entity to measure eligible financial instruments and certain other items at fair value as of specified election dates on an instrument-by-instrument basis (the fair value option). The fair value option is irrevocable unless a new election date occurs. The fair value option will significantly expand an entity's ability to select the measurement attribute for certain key assets and liabilities, and allow it to mitigate potential mismatches that arise under the current mixed measurement attribute model. Statement 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Retrospective application to fiscal years that begin prior to the effective date is not permitted except in connection with early adoption. We adopted Statement 159 as of January 1, 2008, but did not elect the fair value option for any eligible items that existed at that date and the adoption had no effect on our results of operation, financial position or cash flows.

Taxes

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

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

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

Variable interest entities:

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. A business enterprise is required to consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses.

We have power purchase contracts with NUGs. However, we were not involved in the formation of and do not have ownership interests in any NUGs. We have evaluated all of our power purchase contracts with NUGs and determined that most of the purchase contracts are not

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variable interests for one of the following reasons: the contract is based on a fixed price or a market price and there is no other involvement with the NUG, the contract is short-term in duration, the contract is for a minor portion of the NUG's capacity or the NUG is a governmental organization or an individual. One of our NUG contracts expired in April 2006. We are not able to determine if we have variable interests with respect to power purchase contracts with the six remaining NUGs because we are unable to obtain the information necessary to: (1) determine if any of the six NUGs is a variable interest entity, (2) determine if an operating utility is a NUG's primary beneficiary or (3) perform the accounting required to consolidate any of those NUGs. We routinely request necessary information from the six NUGs, and will continue to do so, but no NUG has yet provided the requested information. We did not consolidate any NUGs as of December 31, 2007, 2006 or 2005.

We continue to purchase electricity from the six NUGs at above-market prices. We are not exposed to any loss as a result of our involvement with the NUGs because we are allowed to recover through rates the cost of our purchases. Also, we are under no obligation to a NUG if it decides not to operate for any reason. The combined contractual capacity for the remaining six NUGs is approximately 462 MWs. The combined purchases from the six NUGs totaled approximately $356 million in 2007, $352 million in 2006 and $376 million in 2005.

Note 2. Impairment of Assets and Disposal of Other Businesses

In December 2006 Energy East Telecommunications, Inc. a subsidiary of The Energy Network, Inc. sold its assets for $0.8 million, resulting in no after tax gain or loss. In the fourth quarter of 2005 South Glens Falls Energy, LLC decided to shut down the operation of its 67 MW natural gas-fired peaking co-generation facility located in South Glens Falls, New York. Our subsidiary, Cayuga Energy owned 85% of SGF. The determination to shut down operations was based on SGF's inability to recover costs given the current and forecasted prices for natural gas and electricity. SGF also had an agreement to sell steam that was resulting in ongoing losses. On January 26, 2006, SGF filed for bankruptcy under Chapter 7 of the United States Bankruptcy Code. SGF has ceased operations and in 2005 we recorded an after-tax loss of $5.2 million, representing the impairment of SGF's assets.

Note 3. Goodwill

We do not amortize goodwill, but test it for impairment at least annually. Impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. We had no impairment of goodwill in 2007 and no impairment was indicated within any of the ranges of assumptions analyzed.

The carrying amount of goodwill was the same at December 31, 2007 and 2006. The amounts of goodwill by operating segment (in thousands) are:

Electric Delivery	Natural Gas Delivery	Other	Total
$845,296	$677,080	$3,672	$1,526,048

Note 4. Income Taxes

Year Ended December 31,	2007	2006	2005
(Thousands)			
Current			
Federal	$8,766	$108,025	$87,058
State	(2,134)	16,105	14,800
Current taxes charged to expense	6,632	124,130	101,858
Deferred			
Federal	91,492	22,396	55,821
State	18,993	11,832	15,438
Deferred taxes charged to expense	110,485	34,228	71,259
ITC adjustments	(3,059)	(3,103)	(3,120)
Total	$114,058	$155,255	$169,997

The significant variance in both current and deferred income tax expense in 2007 as compared to prior years is driven primarily by expensing, in accordance with Internal Revenue Code guidelines, certain costs that historically had been capitalized and depreciated for tax purposes. The 2007 amounts represent the effect of that change for both 2006 and 2007 because we first took the position in our 2006 income tax return filed in 2007.

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

Year Ended December 31,	2007	2006	2005
(Thousands)			
Tax expense at statutory rate	$128,270	$145,675	$149,907
Depreciation and amortization not normalized	1,062	7,889	11,859
ITC amortization	(3,059)	(3,119)	(3,120)
Removal Costs	(5,193)	(5,377)	(5,195)
Medicare Subsidy	(4,673)	(4,762)	(2,486)
Out of Period Adjustments	(6,094)	904	(2,434)
State taxes, net of federal benefit	10,959	18,161	19,654
Other, net	(7,214)	(4,116)	1,812
Total	$114,058	$155,255	$169,997

The effective tax rate was 31% in 2007, 37% in 2006 and 40% in 2005. The decrease in the 2007 effective tax rate was primarily due to variances in recurring flow-through items, including the flow-through effect of a book depreciation rate change for NYSEG that went into effect on January 1, 2007, and differences in the 2006 filed tax return compared to the 2006 booked tax expense, primarily due to a change related to the timing of the deductibility of property tax expense for RG&E. The decrease in the 2006 effective tax rate was primarily due to variances in recurring flow-through items, differences in the 2005 filed tax return compared to the 2005 booked tax expense and settlement of an audit of our 2002 and 2003 federal income tax returns. The effective tax rate in prior years is not necessarily indicative of what the effective tax rate will be in future years.

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Our consolidated deferred tax assets and liabilities consisted of:

December 31,	2007	2006
(Thousands)		
Current Deferred Income Tax Assets (Liabilities)		
Derivative (liabilities) assets	$(3,029)	$27,076
	41,412	66,111
Other		
Total Current Deferred Income Tax Assets (Liabilities)	$38,383	$93,187
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property Related	$1,101,266	$993,499
Unfunded future income taxes	129,988	103,385
Accumulated deferred ITC	32,082	35,320
Deferred (gain) on sale of generation assets	(10,340)	(31,718)
Pension	206,873	246,955
Statement 106 postretirement benefits	(123,799)	(119,115)
Other	(8,536)	(18,084)
Total Noncurrent Deferred Income Tax Liabilities (Assets)	1,327,534	1,210,242

Valuation allowance	292	403
Less amounts classified as regulatory liabilities		
Deferred income taxes	5,088	105,528
Noncurrent Deferred Income Tax Liabilities	$1,322,738	$1,105,117
Deferred tax assets	184,086	$262,103
Deferred tax liabilities	1,473,238	1,379,158
Net Accumulated Deferred Income Tax Liabilities	$1,289,152	$1,117,055

Energy East and its subsidiaries have New York state loss carry forwards of $92.5 million, which expire between 2020 and 2027, and an associated valuation allowance of $0.3 million.

See FIN 48 disclosure in Note 1.

Note 5. Long-term Debt

Redemption of debt owed to subsidiary holding solely parent debentures:

In July 2006 we redeemed all of our junior subordinated debt securities owed to a subsidiary at par, financed by the issuance of $250 million of unsecured long-term debt, and by the issuance of short-term debt. The redeemed debt consisted of Energy East's 8 1/4% junior subordinated debt securities that were to mature on July 1, 2031, and were held by Energy East Capital Trust I. We expensed approximately $11 million of unamortized debt expense in July 2006 in connection with the redemption.

At December 31, 2007 and 2006, our consolidated long-term debt was:

				Amount (Thousands)	
Company		Interest Rates	Maturity	2007	2006
	First mortgage bonds [1]				
RG&E	Series B, TT, UU, VV & WW	5.84% - 7.60%	2008 - 2033	$486,000	$511,000
RG&E	PCN 2004 Series A & B (variable)	3.60% - 3.85%	2032	60,500	60,500
SCG	Medium Term Notes I, II & III	5.772% - 7.95%	2008 - 2037	194,000	219,000
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				775,500	825,500
	Unsecured pollution control notes, fixed				
NYSEG	1985 Series A, B & D	4.00% - 4.10%	2015	132,000	132,000
NYSEG	2004 Series C	3.245%	2034	100,000	100,000
RG&E	1998 Series A	5.95%	2033	25,500	25,500
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	19,500	19,500
Total unsecured pollution control notes, fixed				277,000	277,000
	Unsecured pollution control notes, variable				
NYSEG	2006 Series A	3.75%	2024	12,000	12,000
NYSEG	2005 Series A	3.75%	2026	65,000	65,000
NYSEG	2004 Series A & B	3.80% - 3.85%	2027 - 2028	104,000	104,000
NYSEG	1994 Series B, C, D1 & D2	3.50% - 3.60%	2029	175,000	175,000
RG&E	1997 Series A, B & C	3.38% - 3.50%	2032	101,900	101,900
TEN Cos	Industrial Revenue Variable Rate Demand Bonds	3.92%	2025 - 2030	14,900	14,900
Total unsecured pollution control notes, variable				472,800	472,800
	Various long-term debt				
Energy East	Unsecured Note	8.05%	2010	200,000	200,000
Energy East	Unsecured Note	6.75%	2012	400,000	400,000
Energy East	Unsecured Note	6.75%	2033	200,000	200,000
Energy East	Unsecured Notes	6.75%	2036	500,000	500,000
NYSEG	Unsecured Notes	5.50% - 6.15%	2012 - 2023	600,000	550,000
CMP	Series E & F Medium Term Notes	5.10% - 7.00%	2008 - 2035	335,700	310,700
CNG	Medium Term Notes Series A, B & C	5.63% - 9.10%	2008 - 2037	150,000	149,000
Berkshire Gas	Unsecured Notes	4.76% - 9.60%	2011 -	36,000	36,000

			2021		
Energetix	Promissory Note	8.50%	2008	3,509	3,509
TEN Cos	Senior Secured Term Notes	6.90% - 6.99%	2009 - 2010	25,000	30,000
NORVARCO	Promissory and Senior Notes	7.05% - 10.48%	2020	15,190	16,373
Total various long-term debt				2,465,399	2,395,582
Obligations under capital leases				23,073	25,187
Unamortized premium and discount on debt, net				(36,829)	(8,592)
				3,976,943	3,987,477
Less debt due within one year, included in current liabilities				99,914	260,768
Total				$3,877,029	$3,726,709

(1)

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

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.

NYSEG and RG&E have issued $776 million of tax-exempt pollution control notes, $518 million of which have rates that are reset periodically through an auction process that occurs every 7 days for $416 million and every 35 days for the remaining $102 million. The principal and interest on these notes are insured by either XLCA, Ambac, or MBIA. The investors' source of liquidity on these notes is the auction market itself. As the financial strength of bond insurers has been called into question, due in part to their exposure to rising mortgage default rates, investors have reacted by withdrawing from the market, thereby significantly reducing market liquidity and resulting in higher and more volatile interest rates. More recently, as the market became illiquid and broker-dealers withdrew their capital support, an increasing percentage of the auctions, including NYSEG and RG&E auctions, have failed to receive sufficient bids to set new interest rates. In such instances, the issuer is obligated to pay a formulaic failure rate until sufficient bids are received at a scheduled auction. For NYSEG and RG&E, the interest rates resulting from failed auctions are a function of current short-term money market rates multiplied by a factor ranging from 175% to 300%, based on the rating of the applicable bond insurer. To date, failed auction rates for NYSEG and RG&E have ranged from 3.3% to 10.5%. As of February 27, 2008, we were paying formulaic failure rates on $455 million of auction rate debt. The weighted-average interest rate on all $518 million of auction rate securities was 5.6%.

At December 31, 2007, long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years is:

2008	2009	2010	2011	2012
$99,914	$148,986	$261,454	$223,492	$561,995

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 6. 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 2012 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, 2007 and 2006. Energy East pays a facility fee of 10 basis points annually on its $300 million revolver and each joint borrower pays a facility fee on its revolver sublimit, ranging from 6 to 10 basis points annually depending on the rating of its unsecured debt.

We use commercial paper and drawings on our credit facilities to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. There was $138 million of such short-term debt outstanding at December 31, 2007, and $109 million outstanding at December 31, 2006. The weighted-average interest rate on short-term debt was 5.1% at December 31, 2007, and 6.0% at December 31, 2006.

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to

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consolidated total capitalization, we have amended the facility to exclude from consolidated net worth the balance of 'Accumulated other comprehensive income (loss) ' as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness Energy East may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.56 to 1.00 at December 31, 2007. We are not in default, and no condition exists that is likely to create a default, under the facility.

In the revolving credit facility in which our operating utilities are joint borrowers, each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility was amended to exclude from consolidated net worth the balance of 'Accumulated other comprehensive income (loss)' as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to comply with 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 7. Preferred Stock Redeemable Solely at the Option of Subsidiaries

At December 31, 2007 and 2006, our consolidated preferred stock was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding(1)	Amount (Thousands) 2007	2006
CMP, 6% Noncallable	$100	-	5,180	$518	$518
CMP, 4.60%	100	101.00	30,000	3,000	3,000
CMP, 4.75%	100	101.00	50,000	5,000	5,000
CMP, 5.25%	100	102.00	50,000	5,000	5,000
NYSEG, 3.75%	100	104.00	78,379	7,838	7,838
NYSEG, 4.50% (1949)	100	103.75	11,800	1,180	1,180
NYSEG, 4.40%	100	102.00	7,093	709	709
NYSEG, 4.15% (1954)	100	102.00	4,317	432	432
Berkshire Gas, 4.80%	100	100.00	1,596	160	165
CNG, 6.00%	100	110.00	4,104	411	411
CNG, 8.00% Noncallable	3.125	-	108,706	339	339
Total				$24,587	$24,592

(1)

At December 31, 2007, Energy East and its subsidiaries had 16,731,804 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 775,609 shares of $3.125 par value preferred stock, 600,000 shares of $1 par value preferred stock, 10,000,000 shares of $.01 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 6,000,000 shares of $1 par value preference stock authorized but unissued.

Our subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2005 through 2007:

Subsidiary	Date	Series	Amount
			(Thousands)
Berkshire Gas	September 15, 2007	4.80%	$5.5
Berkshire Gas	September 15, 2006	4.80%	$39.3
Berkshire Gas	September 15, 2005	4.80%	$39.9
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 8. Commitments and Contingencies

Capital spending

: We have commitments in connection with our capital spending program. We plan to invest approximately $4 billion in our energy delivery infrastructure during the next five years, including amounts dedicated to electric reliability. We expect that about one-half of our capital spending will be paid for with internally generated funds and the remainder through the issuance of a combination of debt and equity securities. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of energy delivery service, increased transmission capacity, necessary improvements to existing facilities, the installation of an AMI and compliance with environmental requirements and governmental mandates.

Nonutility generator power purchase contracts

: We expensed approximately $529 million for NUG power in 2007, $560 million in 2006 and $631 million in 2005. We estimate that our NUG power purchases will total $393 million in 2008, $230 million in 2009, $85 million in 2010, $86 million in 2011 and $79 million in 2012.

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 $270 million for nuclear entitlement power in 2007, $258 million in 2006 and $263 million in 2005. We estimate that our nuclear entitlement power purchases will be $275 million in 2008, $299 million in 2009, $302 million in 2010, $278 million in 2011 and $185 million in 2012.

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

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available. The two companies have developed an accrual process that incorporates available information about retroactive NYISO billing adjustments as provided to all market participants. However, on an ongoing basis, they cannot fully predict either the magnitude or the direction of any final billing adjustments.

NYPSC Proceeding on NYSEG's Accounting for OPEB

: In August 2006 the NYPSC issued its decision in the NYSEG electric rate case. Among other things, the NYPSC instructed the ALJ to open a separate proceeding regarding the NYPSC staff's position that NYSEG should have retained $57 million of interest in its OPEB reserve and used it to reduce rate base rather than to reduce OPEB expenses. In July 2007 NYSEG, the NYPSC staff and various intervenors filed a joint proposal with the NYPSC resolving all outstanding issues in this matter. On September 20, 2007, the NYPSC approved the joint proposal. The joint proposal provided that NYSEG would refund to customers $17 million from its existing ASGA account and establish an external VEBA trust fund for already-reserved OPEB costs, which are currently deducted from rate base, of approximately $112 million. NYSEG completed the $17 million refund in December 2007. NYSEG contributed $60 million to the VEBA on October 4, 2007, and $52 million on January 15, 2008. The joint proposal also requires pretax charges to earnings for regulatory purposes of $8 million in 2007, $5 million in 2008 and $4 million in 2009. The charges in 2008 and 2009 are expected to be offset by earnings on the VEBA assets.

SGF Bankruptcy Proceeding

: In January 2008, the trustee in the SGF Chapter 7 bankruptcy proceeding brought adversarial proceedings seeking repayment of alleged preferential payments made in the one-year period preceding the bankruptcy filing to SGF affiliates in amounts totaling $14 million. We are evaluating the claims and plan to file responsive pleadings by April 1, 2008. We do not believe there is merit to the claims, but cannot predict the outcome of these claims.

NYPSC Staff Allegations Concerning Earnings Sharing Calculations

: The NYPSC staff in its testimony in the Merger proceeding has alleged that NYSEG did not properly compute the amount due to customers under the electric ESM in NYSEG's electric rate plan that was in effect from 2002 through 2006. The staff claims that its preliminary analysis shows an additional $67 million, including interest, should have been allocated to customers. The staff indicated that its analysis would be completed no later than NYSEG's next electric rate case. NYSEG vigorously disputes the staff's claim. For each year 2002 through 2006 NYSEG made annual compliance filings, as required by the NYPSC. The NYSPC staff has never taken exception to those filings, including during the litigated rate proceeding that resulted in the NYPSC August 2006 rate order. NYSEG is unable to predict when or how the issue will be resolved. The staff also raised issues in the Merger proceeding with regard to the ESM under the RG&E electric rate plan currently in effect, but has not completed its analysis. RG&E believes that it has been properly calculating the amount due to customers in its annual compliance filings since 2004, but cannot predict how the matter will be resolved.

Alleged Overcharges by TEN Companies

: The state of Connecticut filed suit in February 2007 against Energy East and its affiliates - TEN Companies, CNG and CTG Resources - for an alleged $14 million overcharge for heating and cooling services supplied to state buildings since 1992. Subsequently, the state increased its overcharge claim to $30 million. In January 2008 the state filed a motion for injunctive relief to prevent TEN Companies from exercising its right to allow each of the various heating and cooling contracts to expire on their respective expiration dates, and to require TEN Companies to continue to provide heating and cooling service under the agreements. While we believe that there is no merit to these actions, we cannot predict their outcome.

Note 9. Environmental Liability

Environmental liability

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

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

Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $2 million related to 12 of the 22 sites. We have paid remediation costs related to the remaining 10 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of $3 million related to another 14 sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 61 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 two 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 61 sites.

Our estimate for all costs related to investigation and remediation of the 61 sites ranges from $187 million to $385 million at December 31, 2007. 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 $187 million at December 31, 2007, and $162 million at December 31, 2006. We recorded a corresponding regulatory asset, net of insurance recoveries, since we expect to recover the net costs in rates.

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

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Note 10. 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,	2007		2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
Noncurrent investments - classified as available for sale	$86,125	$86,256	$85,386	$85,457
First mortgage bonds	$774,591	$809,495	$824,625	$863,903
Pollution control notes, fixed	$277,000	$279,980	$277,000	$279,143

Pollution control notes, variable	$472,800	$472,800	$472,800	$472,800
Various long-term debt	$2,429,479	$2,472,389	$2,356,290	$2,439,918

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. Current investments available for sale consisted of auction rate securities. These securities have all been sold at par during scheduled auctions.

Note 11. Share-Based Compensation

As of December 31, 2007, we have two share-based compensation plans, which are described below. The total compensation cost recognized in income for those plans for the years ended December 31 was: $15.2 million for 2007, $12.0 million for 2006 and $4.1 million for 2005. The total income tax benefit recognized in income for the share-based compensation arrangements for the years ended December 31 was: $6.1 million for 2007, $4.8 million for 2006 and $1.7 million for 2005.

Stock options/SARs:

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

Effective with our adoption of Statement 123(R) on October 1, 2005 (see Note 1), we began estimating the fair value of each stock option/SAR award using the Black-Scholes-Merton option valuation model and the assumptions noted in the table below. In accordance with Statement 123(R), we measure the fair value of the stock options/SARs on the date of grant, when we begin to recognize compensation cost, and remeasure the fair value at the end of each

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

	2007	2006	2005
Expected volatility	12.01%	12.42%	13.93%
Expected dividends	4.62%	4.49%	4.46%
Expected term (in years)	0.1-5.0	0.2-5.0	0.7-5.0
Risk-free rate	2.95%-3.51%	4.58%-4.99%	4.19%-4.36%

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

The following table provides a summary of stock option/SAR activity under the Plan and other information, for the year ended and as of December 31, 2007.

	Stock Options/ SARs	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (Thousands)
Outstanding at January 1, 2007	3,658,555	$24.03		
Options/SARs granted	979,180	$26.74		
SARs exercised	572,309	$21.78		
Options/SARs forfeited or expired	31,916	$25.09		
Outstanding at December 31, 2007	4,033,510	$25.00	7.15	$8,834
Exercisable at December 31, 2007	2,833,902	$24.63	6.28	$7,346

The weighted-average grant-date fair value of stock options/SARs granted during the years ended December 31 was: $2.30 per share for 2007, $2.47 per share for 2006 and $2.84 per share for 2005. The total intrinsic value of share-based liabilities paid during the years ended December 31 was: $3.3 million for 2007, $0.3 million for 2006 and $10.5 million for 2005.

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 350,000 shares of our common stock in January 2007, primarily for grants of restricted stock. The grant-date fair value of shares of restricted stock awarded is determined using the quoted market price of Energy East's common stock on the date of the restricted stock award and is not subsequently remeasured. We generally expense the compensation cost for restricted stock ratably over the requisite service period; however, compensation cost for certain shares may be expensed immediately or over shorter periods based on the achievement of performance criteria or the retirement provision included in the Restricted Stock Plan. The weighted-average grant date fair value per share of restricted stock granted during the years ended December 31 was: $24.94 for 2007, $24.75 for 2006 and $26.42 for 2005. Under the Merger Agreement, all shares of restricted stock will vest upon consummation of the Merger and become entitled to receive the Merger consideration.

The following table provides a summary of restricted stock activity and other information for the year ended and as of December 31, 2007:

Restricted Stock Plan	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2007	799,436	$24.46
Granted	343,971	24.94
Vested	85,377	19.26
Forfeited	-	-
Nonvested at December 31, 2007	1,058,030	$25.04

As of December 31, 2007, there was $2.2 million of total unrecognized compensation cost related to shares granted pursuant to the Restricted Stock Plan, which we expect to recognize over a weighted-average period of less than one year. The total fair value of shares vested during the years ended December 31 was: $1.6 million for 2007, $1.2 million for 2006 and $2.1 million for 2005.

Note 12. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2005	2005 Change	Balance December 31, 2005	2006 Change [1]	Balance December 31, 2006	2007 Change	Balance December 31, 2007
(Thousands)							
Net unrealized holding (losses) gains on investments, net of income tax (expense) of $(210) for 2005, $(964) for 2006 and $(71) for 2007	$(405)	$333	$(72)	$1,454	$1,382	$116	$1,498
Minimum pension liability adjustment, net of income tax benefit (expense) of $8,674 for 2005 and $(43,850) for 2006	(48,035)	(16,983)	(65,018)	65,018	-	-	-

Amortization of pension cost for nonqualified plans, net of income tax benefit (expense) of $11,153 for 2006 and $(3,263) for 2007	-	-	-	(16,817)	(16,817)	4,916	(11,901)
Unrealized gains (losses) on derivatives qualified as hedges:							
Unrealized gains (losses) during period on derivatives qualified as hedges, net of income tax (expense) benefit of $(107,041) for 2005, $112,687 for 2006 and $12,093 for 2007		167,352		(174,459)		(18,240)	
Reclassification adjustment for (gains) losses included in net income, net of income tax expense (benefit) of $11,987 for 2005, $(7,843) for 2006 and $(24,684) for 2007		(18,056)		11,940		37,245	
Net unrecognized gains on settled cash flow treasury hedges, net of income tax (expense) of $(4,719) for 2007		-		-		7,351	
Net unrealized gains (losses) on derivatives qualified as hedges(2)	4,879	149,296	154,175	(162,519)	(8,344)	26,356	18,012
Accumulated Other Comprehensive (Loss) Income	$(43,561)	$132,646	$89,085	$(112,864)	$(23,779)	$31,388	$7,609

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

(2) See Risk management in Note 1.

Note 13. Retirement Benefits

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

Obligations and funded status

:

	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$2,301,993	$2,366,748	$530,443	$536,997
Service cost	35,113	37,443	5,754	5,852
Interest cost	129,850	127,197	29,690	29,319
Plan participants' contributions	-	-	7,809	25
Plan amendments	521	-	-	247
Actuarial loss (gain)	(74,399)	(93,685)	(16,135)	(5,728)
Benefits paid	(145,270)	(135,710)	(40,308)	(38,275)
Federal subsidy on benefits paid	-	-	2,605	2,006
Benefit obligation at December 31	$2,247,808	$2,301,993	$519,858	$530,443
Change in plan assets				
Fair value of plan assets at January 1	$2,815,425	$2,584,525	$37,301	$31,128
Actual return on plan assets	232,793	366,210	1,635	3,306
Employer contributions	3,000	400	72,334	28,125
Plan participants' contributions	-	-	3,781	25
Benefits paid	(145,270)	(135,710)	(12,433)	(25,283)
Fair value of plan assets at December 31	$2,905,948	$2,815,425	$102,618	$37,301
Funded status at December 31	$658,140	$513,432	$(417,240)	$(493,142)

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	2007	2006	2007	2006
(Thousands)				
Noncurrent assets	$698,432	$577,356	-	-
Current liabilities	-	-	$(5,890)	$(26,228)

Noncurrent liabilities	(40,292)	(63,924)	(411,350)	(466,914)
	$658,140	$513,432	$(417,240)	$(493,142)

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

	Pension Benefits		Postretirement Benefits	
December 31,	2007	2006	2007	2006
(Thousands)				
Net loss (gain)	$130,547	$220,806	$32,024	$51,798
Prior service cost (credit)	$33,988	$38,082	$(21,290)	$(28,723)
Transition obligation	-	-	$34,000	$40,800

Our accumulated benefit obligation for all defined benefit pension plans was $2.1 billion at December 31, 2007 and 2006.

CMP's, CNG's and SCG's postretirement benefits were partially funded at December 31, 2007 and 2006. NYSEG began funding its postretirement benefits with a $60 million contribution to a VEBA in October 2007.

The projected benefit obligation exceeded the fair value of pension plan assets for CMP's, CNG's and SCG's plans as of December 31, 2007 and 2006. The accumulated benefit obligation exceeded the fair value of pension plan assets for CMP's plan as of December 31, 2007, and for CMP's and CNG's plans as of December 31, 2006. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those companies' plans for the relevant periods.

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
December 31	2007	2006	2007	2006
(Thousands)				
Projected benefit obligation	$514,816	$521,945	$264,114	$440,847
Accumulated benefit obligation	$466,720	$467,849	$239,621	$395,586
Fair value of plan assets	$474,524	$458,021	$232,064	$383,046

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities

:

	Pension Benefits			Postretirement Benefits		
Years ended December 31,	2007	2006	2005	2007	2006	2005
(Thousands)						

Net periodic benefit cost						
Service cost	$35,113	$37,443	$35,379	$5,754	$5,852	$5,775
Interest cost	129,850	127,197	127,785	29,690	29,319	30,719
Expected return on plan assets	(232,860)	(221,702)	(214,012)	(3,528)	(1,693)	(2,248)
Amortization of prior service cost (benefit)	**4,615**	4,736	4,994	**(7,433)**	(7,504)	(7,577)
Amortization of net loss (gain)	15,927	22,245	15,887	5,531	6,784	8,630
Amortization of transition (asset) obligation	**-** -		-	**6,800**	6,800	6,800
Net periodic benefit cost	$(47,355)	$(30,081)	$(29,967)	$36,814	$39,558	$42,099
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities						
Net (gain)	$(74,332)			$(14,242)		
Prior service cost	521			-		
Amortization of net (loss)	(15,927)			(5,531)		
Amortization of prior service (cost) credit	(4,615)			**7,433**		
Amortization of transition obligation	**-**			**(6,800)**		
Total recognized in regulatory assets and regulatory liabilities	**(94,353)**			**(19,140)**		
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(141,708)**			**$17,674**		

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost

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deferred at December 31 was $45 million for 2007 and $52 million for 2006. We expect to recover any deferred postretirement costs by 2012. We are amortizing over 20 years the transition obligation for postretirement benefits that resulted from the adoption of Statement 106.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic

benefit cost for the fiscal year ended December 31, 2008	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss (gain)	$14,545	$19,951
Estimated prior service cost (credit)	$4,277	$(3,156)
Estimated transition obligation	-	$6,800

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2008.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

As of December 31, 2007, we increased our discount rate from 5.75% to 6.00%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for	Pension Benefits			Postretirement Benefits		
years ended December 31,	2007	2006	2005	2007	2006	2005
Discount rate	5.75%	5.50%	5.75%	5.75%	5.50%	5.75%
Expected long-term return on plan assets	8.75%	8.75%	8.75%	8.00%	6.00%	8.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes. That analysis considered current capital market conditions and projected conditions. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market-related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2007	2006
Health care cost trend rate assumed for next year	8.0%	9.0%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2014	2011

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

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	$1,721	$(1,429)

Effect on postretirement benefit obligation	$23,375	$(20,039)

Plan assets

: Our weighted-average asset allocations at December 31, 2007 and 2006, by asset category, are:

	Pension Benefits			Postretirement Benefits		
Asset Category	Target Allocation	2007	2006	Target Allocation	2007	2006
Equity securities	58%	60%	64%	60%	58%	47%
Debt securities	27%	26%	24%	35%	37%	40%
Real estate	5%	5%	4%	-	-	-
Other	10%	9%	8%	5%	5%	13%
Total	100%	100%	100%	100%	100%	100%

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

Equity securities did not include any Energy East common stock at December 31, 2007 and 2006.

Contributions

: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $1 million to our pension benefit plans and approximately $60 million to our other postretirement benefit plans in 2008. NYSEG contributed $52 million to its VEBA in January 2008 in accordance with the NYPSC proceeding on NYSEG's accounting for OPEB. (See Note 8.)

Estimated future benefit payments

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

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2008	$142,118	$54,498	$(3,849)
2009	$149,167	$58,451	$(4,253)
2010	$153,271	$62,682	$(4,615)
2011	$160,791	$66,752	$(4,888)
2012	$163,356	$69,387	$(5,230)

2013 - 2017	$877,534	$381,147	$(31,139)

Note 14. Segment Information

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

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
2007				
Operating Revenues	$2,880,994	$1,771,789	$525,325	$5,178,108
Depreciation and Amortization	$179,618	$86,919	$10,953	$277,490
Interest Charges, Net	$183,992	$86,596	$5,350	$275,938
Income Taxes (Benefits)	$71,002	$47,096	$(4,040)	$114,058
Net Income	$156,462	$92,829	$2,007	$251,298
Total Assets	$7,863,420	$3,580,748	$434,541	$11,878,709
Utility Capital Spending	$332,487	$111,522	-	$444,009
2006				
Operating Revenues	$3,023,037	$1,697,601	$510,027	$5,230,665
Depreciation and Amortization	$187,587	$86,728	$8,253	$282,568
Interest Charges, Net	$215,054	$86,263	$7,507	$308,824
Income Taxes (Benefits)	$117,184	$44,744	$(6,673)	$155,255
Net Income	$179,982	$78,166	$1,684	$259,832
Total Assets	$7,184,016	$4,073,320	$305,065	$11,562,401
Utility Capital Spending	$272,486	$135,745	-	$408,231
2005				
Operating Revenues	$2,969,558	$1,783,547	$545,438	$5,298,543
Depreciation and Amortization	$178,806	$85,050	$13,361	$277,217
Interest Charges, Net	$207,074	$81,365	$458	$288,897
Income Taxes	$116,310	$45,752	$7,935	$169,997
Net Income (Loss)	$206,117	$70,121	$(19,405)	$256,833
Total Assets	$7,175,864	$4,136,568	$175,276	$11,487,708
Utility Capital Spending	$214,907	$116,387	-	$331,294

Note 15. Quarterly Financial Information (Unaudited)

Quarter Ended	March 31	June 30	September 30	December 31
(Thousands, except per share amounts)				
2007				
Operating Revenues	$1,713,738	$1,089,026	$1,030,685	$1,344,659
Operating Income	$279,678	$86,726	$69,187	$179,430
Net Income	$133,294	$19,491	$25,042	$73,471
Earnings per Share, basic(1)	$.90	$.12	$.16	$.47
Earnings per Share, diluted(1)	$.90	$.12	$.16	$.46
Dividends Declared per Share	$.30	$.30	$.30	$.31
Average Common Shares Outstanding, basic	147,517	157,112	157,221	157,221
Average Common Shares Outstanding, diluted	148,406	158,122	158,279	158,279
Common Stock Price (2)				
High	$25.93	$27.00	$27.10	$27.90
Low	$23.60	$22.11	$24.83	$26.75
2006				
Operating Revenues	$1,695,611	$1,112,825	$1,090,354	$1,331,875
Operating Income	$294,441	$117,907	$99,911	$191,233
Net Income	$133,241	$28,285	$21,012	$77,294
Earnings per Share basic	$.91	$.19	$.14	$.53
Earnings per Share, diluted	$.90	$.19	$.14	$.53
Dividends Declared per Share	$.29	$.29	$.29	$.30
Average Common Shares Outstanding, basic	147,034	146,903	146,903	147,010
Average Common Shares Outstanding, diluted	147,679	147,678	147,702	147,809
Common Stock Price (2)				
High	$25.57	$25.39	$25.20	$25.66
Low	$22.98	$22.18	$23.36	$23.62

(1)

The sum of quarterly EPS does not equal annual EPS because of our common stock issuances early in 2007.
(2) Our common stock is listed on the New York Stock Exchange. The number of shareholders of record was 27,912 at December 31, 2007.

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Report of Independent Registered Public Accounting Firm

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

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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Energy East Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* and effective December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with

authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 28, 2008

SCHEDULE II - Consolidated Valuation and Qualifying Accounts

Years Ended December 31, 2007, 2006 and 2005

Classification	Beginning of Year	Additions	Write-offs	End of Year
(Thousands)				
2007				
Allowance for Doubtful Accounts - Accounts Receivable	$59,253	$50,638	(59,053)[1]	$50,838
Income Tax Valuation Allowance	$400	-	(108)	292
2006				
Allowance for Doubtful Accounts - Accounts Receivable	$53,112	$65,199	$(59,058)[1]	$59,253
Income Tax Valuation Allowance	-	$400	-	$400
2005				
Allowance for Doubtful Accounts - Accounts Receivable	$45,344	$72,123	($64,355)[1]	$53,112

(1)

Uncollectible accounts charged against the allowance, net of recoveries.

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

None.

Item 9A. Controls and Procedures

Management's Annual Report on Disclosure Controls and Procedures

Our principal executive officer and principal financial officer evaluated the effectiveness of our 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 officer and principal financial officer concluded that our disclosure controls and procedures are effective.

Management's Annual Report on Internal Control Over Financial Reporting

Our 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 our evaluation under the framework in *Internal Control - Integrated Framework*, management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page

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Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART

III

Information required by Part III is incorporated herein by reference to the information under the caption(s), indicated in the table below, in Energy East's Proxy Statement, which will be filed with the Commission on or before April 29, 2008.

Caption(s) in Energy East's Proxy Statement

Item 10. Directors, Executive Officers and Corporate Governance	"Corporate Governance, " "Committees, " "Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance"
Item 11. Executive Compensation	"Compensation Discussion and Analysis, " "Compensation Committee Report, " "Summary Compensation Table, " "Grants of Plan-Based Awards, " "Outstanding Equity Awards at Fiscal Year End," "Option Exercises and Stock Vested, " "Pension Benefits, " "Summary of Potential Post Employment Termination Payments, " "Directors' Compensation, "
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	"Security Ownership of Certain Beneficial Owners and Management"
Item 13. Certain Relationships and Related Transactions, and Director Independence	"Election of Directors," "Related Party Transactions Policy"
Item 14. Principal Accounting Fees and Services	"Independent Accountants, " "Audit Fees, " "Audit-Related Fees, " "Tax Fees" and "All Other Fees"

Information for Item 10 regarding our executive officers is on page

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PART IV

Item 15. Exhibits, Financial Statement Schedule

The following documents are filed as part of this report:

Financial statements

Included in Part II of this report:

Consolidated Balance Sheets as of December 31, 2007 and 2006

For the three years ended December 31, 2007

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, 2007

II. Consolidated 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 or notes thereto.

Exhibits

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

Exhibit No.	Description
(A)10-20 -	Letter Agreement amending Amended and Restated Employment Agreement dated as of June 14, 1999, by and among the Company, CMP Group, Inc. and F. Michael McClain, Jr.
(A)10-29 -	Form of Letter Agreement amending Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement.
(A)10-31 -	Form of Letter Agreement amending Energy East Management Corporation Form of Severence Agreement for executive officers who do not have employment agreements.
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.

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

(A) Management contract or compensatory plan or arrangement.

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

Exhibit No.	Filed in	As Exhibit No.
2-1 -	Agreement and Plan of Merger dated as of June 25, 2007 among the Company, Iberdrola, S.A. and Green Acquisition Capital, Inc. - Company's 8-K dated June 25, 2007 - File No. 1-14766	2-1
3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New York on April 23, 1998 - Post-effective Amendment No.1 to Registration No. 033-54155	4-1
3-2 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on April 26, 1999 - Company's 10-Q for the quarter ended March 31, 1999 - File No. 1-14766	3-3

3-3 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 21, 2004 - Company's 10-Q for the quarter ended June 30, 2004 - File No. 1-14766	3-5
3-4 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 12, 2006 - Company's 10-Q for the quarter ended June 30, 2006 - File No. 1-14766.	3-6
3-5 -	By-laws of the Company as amended April 12, 2007 - Company's 8-K dated April 13, 2007 - File No. 1-14766	3-6
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 -	Sixth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of June 14, 2002, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended June 30, 2002 - File No. 1-14766	4-6
4-4 -	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
4-5 -	Eighth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2006, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000 - Company's 10-Q for the quarter ended September 30, 2006 - File No. 1-14766	4-8
(A)10-1 -	Deferred Compensation Plan for Directors - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-40
(A)10-2 -	Amended and Restated Director Share Plan - Company's 10-Q for the quarter ended September 30, 2000 - File No. 1-14766	10-38
(A)10-3 -	Amendment No. 1 to Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-3

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Exhibit No.	Filed in	As Exhibit No.
(A)10-4 -	Amendment No. 2 to Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-4
(A)10-5 -	Deferred Compensation Plan - Director Share Plan - Company's 10-Q for	

	the quarter ended September 30, 2000 - File No. 1-14766	10-39
(A)10-6 -	Amendment No. 1 to Deferred Compensation Plan - Director Share Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-6
(A)10-7 -	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)10-8 -	Amendment No. 1 to Deferred Compensation Plan - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-16
(A)10-9 -	Supplemental Executive Retirement Plan - Company's 10-Q for the quarter ended September 30, 2001 - File No. 1-14766	10-33
(A)10-10 -	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)10-11 -	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)10-12 -	Supplemental Executive Retirement Plan Amendment No. 3 - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-10
(A)10-13 -	Supplemental Executive Retirement Plan Amendment No. 4 - Company's 10-Q for the quarter ended June 30, 2007 - File No. 1-14766	10-32
(A)10-14 -	Annual Executive Incentive Plan - Company's 10-K for the year ended December 31, 2000 - File No. 1-14766	10-8
(A)10-15 -	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)10-16 -	Annual Executive Incentive Plan Amendment No. 2 - Company's 10-Q for the quarter ended June 30, 2001 - File No. 1-14766	10-28
(A)10-17 -	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)10-18 -	Amended and Restated Employment Agreement dated as of June 25, 2007, by and among Iberdrola, S.A., the Company, Energy East Management Corporation and W.W. von Schack - Company's 10-Q for the quarter ended September 30, 2007 - File No. 1-14766	10-33
(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)10-21 -	Restricted Stock Plan - Company's 10-K for the year ended December 31, 1998 - File No. 1-14766	10-36
(A)10-22 -	Restricted Stock Plan Amendment No. 1 - Company's 10-K for the year ended December 31, 2002 - File No. 1-14766	10-16
(A)10-23 -	Form of Restricted Stock Award Grant - Company's 10-Q for the quarter ended March 31, 2005 - File No. 1-14766	10-23
(A)10-24 -	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)10-25 -	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)10-26 -		

	Award Agreement (February 2007) under the 2000 Stock Option Plan - Company's 10-K for the year ended December 31, 2006 - File No. 1-14766	10-26
(A)10-27 -	Amended and Restated Director's Charitable Giving Program - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-27

Exhibit No.	Filed in	As Exhibit No.
(A)10-28 -	Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement - Company's 10-K for the year ended December 31, 2001 - File No. 1-14766	10-24
(A)10-30 -	Energy East Management Corporation Form of Severance Agreement for executive officers who do not have employment agreements - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-29
(A)10-32 -	ERISA Excess Plan effective January 1, 2005 - Company's 10-K for the year ended December 31, 2005 - File No. 1-14766	10-30
(A)10-33 -	ERISA Excess Plan Amendment No. 1 - Company's 10-Q for the quarter ended June 30, 2007 - File No. 1-14766	10-31

(A) Management contract or compensatory plan or arrangement.

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

A. Five-Year Revolving Credit Agreement among Energy East, certain lenders, Citibank, N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent and HSBC Bank USA, National Association, UBS Securities LLC and Wachovia Bank, N.A., as Co-Documentation Agents, as amended and restated as of June 2, 2006, and as further amended by a First Amendment, dated as of May 16, 2007.

B. Five-Year Revolving Credit Agreement among Rochester Gas and Electric Corporation (RG&E), New York State Electric & Gas Corporation (NYSEG), Central Maine Power Company, The Southern Connecticut Gas Company, Connecticut Natural Gas Corporation and The Berkshire Gas Company, certain lenders, Wachovia Bank N.A., as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent and The Bank of New York, Citibank, N.A. and Sovereign Bank, as Co-Documentation Agents, as amended and restated as of May 16, 2007 (the "Joint Revolving Credit Agreement").

C. Indenture dated as of November 18, 2002, between NYSEG and The Bank of New York (as successor to JPMorgan Chase Bank), as Trustee, and the Supplemental Indentures related thereto.

D. General Mortgage dated September 1, 1918, from RG&E to Deutsche Bank Trust Company Americas (formerly Bankers Trust Company), as Trustee, and the Supplemental Indentures related thereto.

E. Participation Agreements dated as of March 1, 1985, October 15, 1985, and December 1, 1985, between NYSEG and NYSERDA relating to Annual Tender Pollution Control Revenue Bonds (1985 Series A), (1985 Series B) and (1985 Series D), respectively; Participation Agreements dated as of February 1, 1994, June 1, 1994, October 1, 1994, and December 1, 1994, between NYSEG and NYSERDA relating to Pollution Control Refunding Revenue Bonds, (1994 Series B), (1994 Series C) and (1994 Series D), respectively; Participation Agreements dated as of August 1, 2004, between NYSEG and NYSERDA relating to Pollution Control Revenue Bonds (2004 Series A), (2004 Series B) and (2004 Series C); Participation Agreement dated as of May 1, 2005, between

NYSEG and NYSERDA relating to Pollution Control Revenue Bonds (2005 Series A); and Loan Agreement between NYSEG and the Indiana County Industrial Development Authority relating to Pollution Control Refunding Revenue Bonds (Series 2006).

F. Participation Agreement dated as of August 1, 1997, between RG&E and New York State Energy Research and Development Authority (NYSERDA) relating to Pollution Control Revenue Bonds, RG&E Project (1997 Series A), (1997 Series B), (1997 Series C) and (1998 Series A); and 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).

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

H. 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).

I. 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.

J. 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.

K. 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.

L. 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.

M. 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.

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

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

P. 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.

Signatures

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

ENERGY EAST CORPORATION

Date: February 29, 2008 By /s/Robert D. Kump

Robert D. Kump
Senior Vice President and
Chief Financial Officer

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

PRINCIPAL EXECUTIVE OFFICER

Date: February 29, 2008 By /s/Wesley W. von Schack
Wesley W. von Schack
Chairman, President, Chief
Executive Officer & Director

PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER

Date: February 29, 2008 By /s/Robert D. Kump
Robert D. Kump
Senior Vice President and
Chief Financial Officer

Signatures

(Continued)

Date: February 29, 2008 By /s/James H. Brandi
James H. Brandi, Director

Date: February 29, 2008 By /s/John T. Cardis
John T. Cardis, Director

Date: February 29, 2008 By /s/Thomas B. Hogan, Jr.
Thomas B. Hogan, Jr., Director

Date: February 29, 2008 By /s/G. Jean Howard
G. Jean Howard, Director

Date: February 29, 2008 By /s/David M. Jagger
David M. Jagger, Director

Date: February 29, 2008 By /s/Seth A. Kaplan
Seth A. Kaplan, Director

Date: February 29, 2008 By /s/Ben E. Lynch
Ben E. Lynch, Director

Date: February 29, 2008

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

Date: February 29, 2008

By /s/Patricia M. Nazemetz
Patricia M. Nazemetz, Director

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EXHIBIT INDEX

Exhibit No.	Description
*2-1 -	Agreement and Plan of Merger dated as of June 25, 2007 among the Company, Iberdrola, S.A. and Green Acquisition Capital, Inc.
*3-1 -	Restated Certificate of Incorporation of the Company pursuant to Section 807 of the Business Corporation Law filed in the Office of the Secretary of State of the state of New York on April 23, 1998.
*3-2 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on April 26, 1999.
*3-3 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 21, 2004.
*3-4 -	Certificate of Amendment of the Certificate of Incorporation filed in the Office of the Secretary of State of the state of New York on June 12, 2006.
*3-5 -	By-Laws of the Company as amended April 12, 2007.
*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 -	Sixth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of June 14, 2002, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
*4-4 -	Seventh Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of September 9, 2003, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
*4-5 -	Eighth Supplemental Indenture between the Company and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, dated as of July 24, 2006, related to the Indenture between the Company and JPMorgan Chase Bank, as Trustee, dated as of August 31, 2000.
*(A)10-1 -	Deferred Compensation Plan for Directors.
*(A)10-2 -	Amended and Restated Director Share Plan.
*(A)10-3 -	Amendment No. 1 to Director Share Plan.

*(A)10-4 - Amendment No. 2 to Director Share Plan.

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

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

*(A)10-7 - Deferred Compensation Plan, effective January 1, 2004.

*(A)10-8 - Amendment No. 1 to Deferred Compensation Plan.

*(A)10-9 - Supplemental Executive Retirement Plan.

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

*(A)10-11 - Supplemental Executive Retirement Plan Amendment No. 2.

*(A)10-12 - Supplemental Executive Retirement Plan Amendment No. 3.

*(A)10-13 - Supplemental Executive Retirement Plan Amendment No. 4.

*(A)10-14 - Annual Executive Incentive Plan.

*(A)10-15 - Annual Executive Incentive Plan Amendment No. 1.

*(A)10-16 - Annual Executive Incentive Plan Amendment No. 2.

*(A)10-17 - Annual Executive Incentive Plan Amendment No. 3.

*(A)10-18 - Amended and Restated Employment Agreement dated as of June 25, 2007, by and among Iberdrola, S.A., the Company, Energy East Management Corporation and W. W. von Schack.

*(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.

(A)10-20 - Letter Agreement amending Amended and Restated Employment Agreement dated as of June 14, 1999, by and among the Company, CMP Group, Inc. and F. Michael McClain, Jr.

Exhibit No. Description

*(A)10-21 - Restricted Stock Plan.

*(A)10-22 - Restricted Stock Plan Amendment No. 1.

*(A)10-23 - Form of Restricted Stock Award Grant.

*(A)10-24 - Amended and Restated 2000 Stock Option Plan, effective October 15, 2003.

*(A)10-25 - Award Agreement under the 2000 Stock Option Plan.

*(A)10-26 - Award Agreement (February 2007) under the 2000 Stock Option Plan.

*(A)10-27 - Amended and Restated Director's Charitable Giving Program.

*(A)10-28 - Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement.

(A)10-29 - Form of Letter Agreement amending Energy East Management Corporation Form of Employee Invention and Confidentiality Agreement.

*(A)10-30 -	Energy East Management Corporation Form of Severance Agreement for executive officers who do not have employment agreements.
(A)10-31 -	Form of Letter Agreement amending Energy East Management Corporation Form of Severance Agreement for executive officers who do not have employment agreements.
*(A)10-32 -	ERISA Excess Plan effective January 1, 2005.
*(A)10-33 -	ERISA Excess Plan Amendment No. 1.
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.

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

(A) Management contract or compensatory plan or arrangement.