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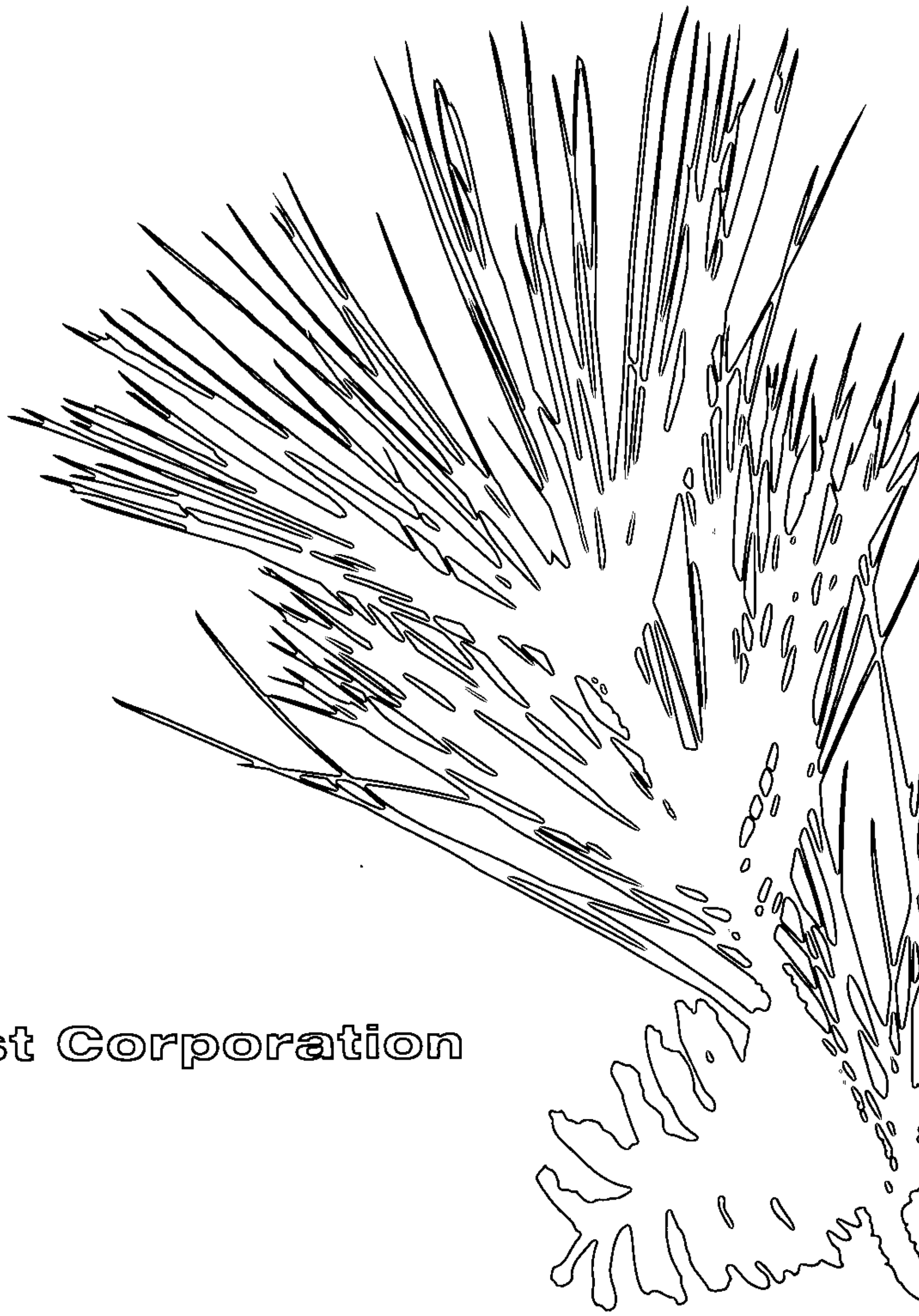
# ANNUAL REPORT 2006

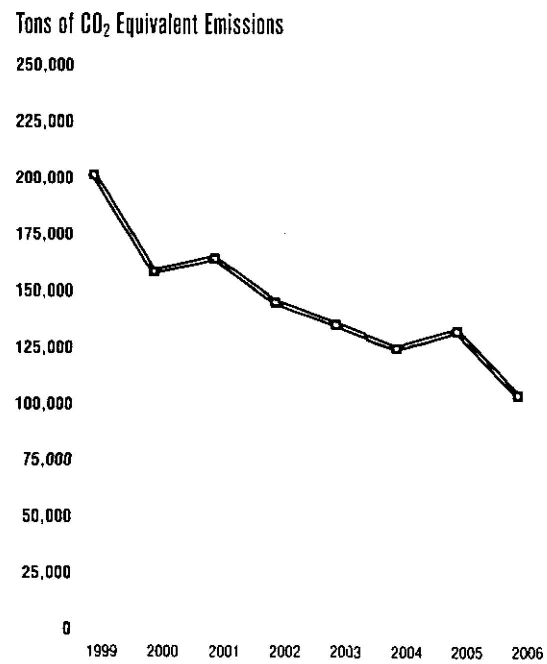




# Energy East Corporation

**Energy East is committed to meeting high standards of environmental stewardship in the communities we serve and to conducting business in a manner that minimizes adverse environmental impacts on present and future generations.**

Energy East's utilities have reduced their carbon dioxide ($CO_2$) equivalent emissions nearly 50% in the past seven years. Major initiatives supporting this reduction include a significant focus on reducing sulfur hexafluoride ($SF_6$) emissions, aggressive leak detection programs at our natural gas companies to minimize methane emissions, improvements in gasoline efficiency for our fleet vehicles, and the overall efficiency of our buildings. These reductions are the equivalent of planting over 13 million trees or taking nearly 17,000 cars off the road.



# ENVIRONMENTAL POLICY




**The following principles and actions provide a framework for Energy East's environmental stewardship and sustainable business practices:**

- Design an Environmental Management System that enables us to systematically plan, implement and continually improve the processes and actions we take to meet our business and environmental goals;
- Comply with all applicable requirements of environmental laws, regulations, permit requirements and company policies applicable to our operations;
- Incorporate environmental impact considerations into decision-making processes concerning existing and future operations;
- Support the conservation of energy and natural resources through strategic planning, efficient operating practices, technology and consumer education;
- Minimize waste through recycling and other means, and properly manage any waste that is created;
- Support and implement actions designed to reduce greenhouse gas emissions and counteract global climate change;
- Foster a culture where employees have the encouragement, training, knowledge and resources necessary to perform their job in a manner consistent with this policy;
- Participate in the development of standards and guidelines in support of environmental stewardship;
- Communicate and demonstrate our commitment to sound environmental policies and practices; and
- Support others who share Energy East's commitment to environmental stewardship and sustainable development.

*Implementation of this policy is the responsibility of all Energy East people. The Board of Directors regularly reviews environmental strategies and performance under this policy.*

# INCORPORATING ENVIRONMENTAL STEWARDSHIP IN OUR DAY-TO-DAY OPERATIONS

**Global Roundtable on Climate Change** Climate change is an urgent problem that requires global action to reduce emissions of greenhouse gases in a time frame that minimizes the risk of serious human impact on the Earth's natural systems. While undeniably complex, confronting the issue of climate change depends, in many ways, on developing and deploying low-carbon energy technologies. Energy East's goal in participating in the Global Roundtable on Climate Change is to create a greater global consensus on core aspects of a realistic policy on climate change; one that seeks the simultaneous objectives of effectively mitigating climate change while also creating the sustainable energy systems necessary to achieve long-term economic development and growth for all nations.

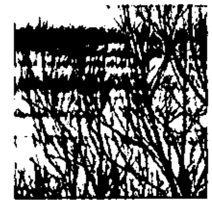
**Reducing $SF_6$ Emissions** Energy East has been a leader in the EPA self compliance program for $SF_6$ gas losses. $SF_6$ is non-toxic gas used as an insulator in breakers whose warming effect is 24,000 times greater than $CO_2$. Critical to our success was the installation of new primary breakers that require less $SF_6$ and aggressive leak detection, thereby reducing our risk of $SF_6$ losses.

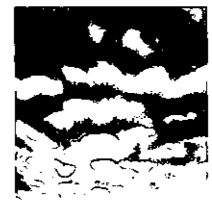
**Hydroelectric Power** Thanks to Mother Nature and capital improvements at our hydroelectric stations, NYSEG and RG&E saw a combined 14% increase in hydroelectric generation in 2006, offsetting the need for electricity from traditional $CO_2$ producing generation sources. As a result we avoided 408,000 tons of $CO_2$, 2,100 tons of sulfur dioxide ($SO_2$) and 570 tons of nitrogen oxides. The $CO_2$ emissions avoided are the equivalent of planting 55 million trees or not driving about 700 million miles. In 2007 NYSEG and RG&E will be making additional strategic investments in these generation facilities to preserve their operations and increase their potential generation capacity.

**Protecting Ospreys** In 2006 CMP began replacement of an 8.5 mile, 34.5 kilovolt line to enhance service to several central Maine communities. The line passes through osprey nesting areas, which pose outage risk and danger for fledgling osprey. As a part of the project, CMP erected separate platforms at choice nesting sites to attract ospreys away from the line, improving both service reliability and osprey safety.

**40,000 Tons of Coal Displaced** During 2006 Berkshire Gas completed the construction of a natural gas pipeline to serve a new central heating facility at the University of Massachusetts in Amherst. This new facility will displace some 40,000 tons of coal annually previously burned by the old facility, resulting in $CO_2$ reductions equivalent to planting 8 million trees or taking over 10,000 cars off the road.

**Reliability** Digital products rely on electricity-driven signals to operate and almost every piece of equipment in the modern business or home is digital. Electric reliability has taken on new meaning and NYSEG and RG&E are responding through their Transmission and Distribution Infrastructure Reliability Programs. The programs represent a multi-year investment of $900 million. While current reliability indices and system performance remain excellent, we recognize the need to stay ahead of customer expectations. In 2006 more than 100 projects were completed under these programs, including the replacement of transformers, conductors, poles and other equipment using more efficient and environmentally friendly materials.





**Wind Generation** NYSEG and RG&E experienced a 150% increase in participation in their "Catch the Wind" programs in partnership with Community Energy Inc., a leading marketer of wind energy. Because wind-generated electricity offsets the need for electricity from traditional $CO_2$ producing electricity sources there is a direct benefit to the environment from every customer purchase. For example, a customer who buys 200 kilowatt-hours of wind energy each month for a year is directly responsible for reducing $CO_2$ emissions the equivalent of planting about 150 trees or not driving 2,000 miles.

**Natural Gas Leak Detection** NYSEG's and RG&E's leak repair and main replacement programs have resulted in an estimated savings of 28 tons of natural gas per year, the equivalent greenhouse gas reduction of 560,000 tons of $CO_2$. NYSEG and RG&E are the only natural gas companies in New York State with a comprehensive leak detection and repair program where all classifications of leaks are repaired. NYSEG completed the replacement of all cast iron mains in its natural gas delivery system in 2005. Since 1998 RG&E has replaced nearly 110 miles of cast iron mains, and RG&E will continue a regular program of replacing these mains until all cast iron has been removed. NYSEG and RG&E have also replaced approximately 200 miles of bare steel mains.

**Pipeline Drip Water Filtration** In 2006 CNG implemented a program which filters out debris collected through the removal of liquids which have infiltrated our underground system. These liquids must be removed for the safe operation of the system and contain debris which can be harmful to the environment. Working with the Connecticut Department of Environmental Protection, we have developed a process where we filter out all debris from these pipeline liquids. The remaining liquids are subsequently tested to ensure they are free of any contaminates.

# FINANCIAL HIGHLIGHTS

| **Per Common Share** | **2006** | 2005 | % Change |
|---|---|---|---|
| Earnings, basic | **$1.77** | $1.75 | 1 |
| Earnings, diluted | **$1.76** | $1.74 | 1 |
| Dividends Declared | **$1.17** | $1.115 | 5 |
| Book Value at Year End | **$19.37** | $19.45 | - |
| Price at Year End | **$24.80** | $22.80 | 9 |
| **Other Common Stock Information** (Thousands) | | | |
| Average Common Shares Outstanding, basic | **146,962** | 146,964 | - |
| Average Common Shares Outstanding, diluted | **147,717** | 147,474 | - |
| Common Shares Outstanding at Year End | **147,907** | 147,701 | - |
| **Operating Results** (Thousands) | | | |
| Total Operating Revenues | **$5,230,665** | $5,298,543 | (1) |
| Total Operating Expenses | **$4,527,173** | $4,605,388 | (2) |
| Net Income | **$259,832** | $256,833 | 1 |
| Energy Distribution: | | | |
| Megawatt-hours | | | |
| Retail Deliveries | **31,133** | 32,019 | (3) |
| Wholesale Deliveries | **9,317** | 9,466 | (2) |
| Dekatherms | | | |
| Retail Deliveries | **188,279** | 204,677 | (8) |
| Wholesale Deliveries | **111** | 883 | (87) |
| **Total Assets at Year End** (Thousands) | **$11,562,401** | $11,487,708 | 1 |

**We are a motivated and skilled team of professionals dedicated to creating shareholder value through our focus on profitable growth, operational excellence and strong customer partnerships.**

February 28, 2007

Dear Shareholders:

Our ability to continue to provide outstanding customer service helped us achieve another solid year for your investment in Energy East. Including dividends your stock returned 14% in 2006. For the past 10 years your investment in Energy East has returned 13% on an annualized basis, significantly outperforming the S&P Utility index, which has returned 8% annually.

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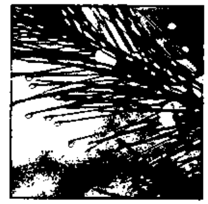
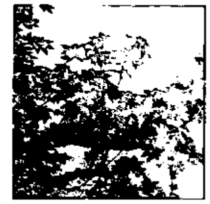
In October 2006 the Board of Directors increased the common stock dividend 4 cents or 3.4%. 2006 was the ninth consecutive year of dividend increases during which your dividend has increased nearly 70%. The Board remains committed to sustainable growth in the dividend consistent with our targeted dividend payout ratio of about 75% of earnings.

Energy East continues to be recognized as one of the best distribution companies for customer service and reliability. During 2006, we were once again rated as one of the top electric utilities in the eastern United States for customer satisfaction by JD Power & Associates. We are also recognized for our environmental stewardship. In an independent survey done last year, Central Maine Power received the highest mark among 13 northeastern utilities for its commitment to protecting the environment. As you can see, we have dedicated this year's Annual Report to our strong environmental track record.

In last year's Annual Report, I discussed Energy East's focus on capital investments to help ensure a safe, secure, reliable and efficient energy infrastructure. We recently increased our capital spending plan to further address critical infrastructure needs in the Northeast in an environmentally responsive manner. This revised spending plan is expected to total more than $3 billion over the next five years, an increase of over $1 billion from last year's projection. Core to this revised plan is $900 million for electric system reliability in upstate New York and in excess of $500 million for Central Maine Power's "Maine Power Reliability Program".



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Our major transmission initiatives in Maine address both local reliability issues and issues affecting New England, which meet the concerns of The New England Independent System Operator and the Federal Energy Regulatory Commission (FERC). The FERC has acknowledged the need for greater transmission investment, calling the chronic underinvestment a national problem. These initiatives would also support the development of renewable energy, particularly proposed wind farms in northern and western Maine that require additional transmission capacity to the south.

About $500 million will be invested in "carbon reduction" technologies, such as advanced metering infrastructure (AMI), high efficiency transformers and hybrid fleet vehicles. There is strong evidence regarding the effect of various greenhouse gases on our environment and we are taking a leadership role in developing environmentally friendly solutions to the growing demand for energy.

Investments in AMI, which was recently endorsed by the National Association of Regulatory Utility Commissioners, will provide a platform for our customers to shift usage from peak service times to off-peak periods thereby reducing the amount of new generation needed in the future. AMI will also provide customers with pricing information throughout the day to encourage conservation and contribute to our carbon reduction effort.

We also have an initiative to replace old transformers with newer, more efficient models that will reduce line losses, giving customers more energy for their dollar. Investments in AMI and high efficiency transformers will improve customer service, reliability, and the security of our electric distribution systems in New York and Maine, and help lower wholesale energy prices by reducing customer demand. We estimate that future investments will ultimately avoid nearly 1 million megawatt hours of electricity usage annually, which equates to $CO_2$ reductions of close to 1 million tons a year. This is the equivalent of taking about 175,000 cars off the road.

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We also expect to play an expanded role in meeting customers' energy needs through environmentally friendly generation. We will be looking to expand our hydroelectric fleet, which is the third largest in New York, as well as participate in the development of wind projects in the Northeast. We also intend to repower the 257 megawatt coal-fired Russell Station in Rochester using clean coal technologies.

In closing, 2006 was not without its disappointments. Earnings in 2007 are expected to decline by about 25 to 30 cents per share compared to 2006. This is due in large part to a 2006 regulatory policy decision to make several changes to NYSEG's popular Voice Your Choice program, namely an unacceptable allowance to cover the costs and risks we assume in providing customers a fully bundled fixed price, including energy supply. This program had been overwhelmingly received by customers since its inception in 2003.

We believe Energy East is in an excellent position to grow long-term and help solve the energy issues we face in upstate New York and New England. Our confidence is made possible thanks to the hard work and dedication of our people who have made us one of the best, most respected utilities in the nation.

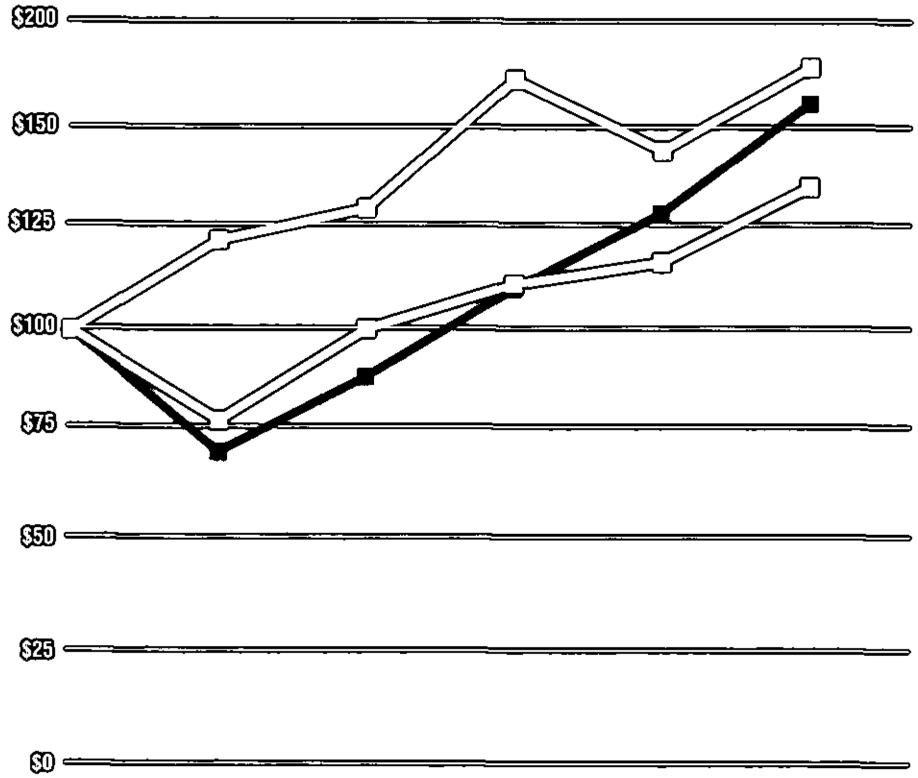
We thank all of our people and you, our shareholders, for your investment.

On behalf of the Board of Directors,

Wes Von Schack

Wesley W. von Schack
Chairman and Chief Executive Officer

**Stock Performance Graph**
The yearly change in the cumulative total shareholder return on Energy East's common stock during the five years ending December 31, 2006, compared with the cumulative total return on the Standard & Poor's 500 Index and the Standard & Poor's Utilities Index assuming $100 was invested on December 31, 2001, and assuming reinvestment of dividends.




| Year Ended December 31 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|
| Energy East Corporation | $100.00 | $121.91 | $129.66 | $161.28 | $143.91 | $164.28 |
| Standard & Poor's 500 | $100.00 | $77.90 | $100.24 | $111.15 | $116.61 | $135.02 |
| Standard & Poor's Utilities | $100.00 | $70.01 | $88.39 | $109.85 | $128.35 | $155.29 |

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

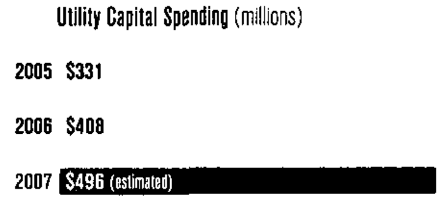
## OVERVIEW

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

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

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

We expect to make significant capital investments to enhance the safety and reliability of our distribution systems and to meet the growing energy needs of our customers in an environmentally friendly manner.




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

## STRATEGY

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

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

## ELECTRIC DELIVERY RATE OVERVIEW

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

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

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

RG&E's current rates were established by the 2004 Electric Rate Agreement, which addresses RG&E's electric rates through at least 2008. Key features of the Electric Rate Agreement include freezing electric delivery rates through December 2008, except for the implementation of a retail access surcharge effective May 1, 2004, to recover $7 million annually. An ASGA was established that was originally estimated to be $145 million at the end of 2008 and will be used at that time for rate moderation or other purposes at the discretion of the NYPSC. The Electric Rate Agreement also established an earnings-sharing mechanism to allow customers and shareholders to share equally in earnings above a 12.25% ROE target. Earnings levels were sufficient to generate $6 million of pretax sharing in 2006 and $23 million in 2005.

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

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

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

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

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

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

## ELECTRIC DELIVERY BUSINESS DEVELOPMENTS

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

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

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

- A decrease in delivery rates of $36 million. NYSEG's most recent update in the proceeding requested a $58 million increase in delivery rates.
- A 9.55% ROE. NYSEG had requested an 11% ROE.
- An equity ratio of 41.6% (approximately $610 million of equity) based on Energy East's consolidated capital structure. NYSEG had requested a 50% equity ratio based on its actual capital structure.
- A refund of $77 million to be paid from NYSEG's ASGA that had previously been reserved for customers. The ASGA was initially created in 1998 as a result of the sale of NYSEG's generating stations and had been enhanced during NYSEG's prior electric rate plans with the customers' share of earnings from the earnings sharing mechanism. Payment of the refund will be made through a credit to customers' bills by the end of April 2007.
- One retroactive accounting issue raised by Staff concerns $57 million of interest associated with NYSEG's internal OPEB reserve, which NYSEG has offset against other OPEB costs in its income statement over the past decade. The NYPSC determined that $3.6 million in annual revenues that NYSEG receives will remain subject to refund pending further examination of NYSEG's accounting for OPEB costs. A proceeding related to this issue began in the fourth quarter of 2006 and could result in NYSEG treating all or a portion of the $57 million as an addition to its internal OPEB reserve, with a corresponding charge to income. NYSEG is vigorously defending its position and contends that the NYPSC staff is engaged in retroactive ratemaking, but is unable to predict its outcome.
- Significant modifications to NYSEG's previously approved Voice Your Choice commodity program, including:
  - Use of the variable rate supply option as the default for all customers not making a supply election, rather than the previous fixed price default option.
  - A 30% reduction in the cost allowance used to set the supply rate.

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

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

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

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

**Niagara Power Project Relicensing** The NYPA's FERC license with respect to the Niagara Power Project expires on August 31, 2007. In order to continue to operate the Niagara Power Project, the NYPA filed a relicensing application in August 2005. The NYPA's relicensing process is important to NYSEG's and RG&E's customers because an aggregate of over 360 MWs of Niagara Power Project power has been allocated to the companies based on their contracts with the NYPA. (NYSEG and RG&E also receive allocations from the St. Lawrence Project pursuant to those same contracts.) The contracts expire on August 31, 2007, upon termination of the NYPA's FERC license. The annual value of the Niagara allocation to the companies at current electricity market prices is approximately $77 million and the loss of the allocation would increase NYSEG's and RG&E's residential customer rates. However, the NYPA has stated that the allocation of Niagara Power Project power to NYSEG and RG&E should not be addressed in the relicensing proceeding and that the disposition of the power will be in accordance with state and federal requirements.

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

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

In early February 2005 NYSEG and RG&E filed, with two other New York State utilities, a joint petition for rehearing that focused on several areas including the impracticability of the timetable established in the order. In response to the order, in late February 2005 NYSEG and RG&E filed a testing and inspection plan that is consistent with the timetable identified in the joint petition for rehearing. NYSEG and RG&E

are implementing their plans, including testing of equipment. On July 21, 2005, in response to the petition for rehearing, the NYPSC issued an order detailing the revised requirements for stray voltage testing and reduced penalties during the first year to 37.5 basis points. NYSEG and RG&E filed the required annual reports with the NYPSC on January 17, 2006. In August 2006 NYSEG and RG&E completed their first complete cycle of testing and at the request of the NYPSC, submitted an interim report on October 23, 2006, detailing their results. Under the provisions of their respective rate plans, they are allowed to defer and recover these costs.

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

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

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

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

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

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

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

**CMP Alternative Rate Plan** In December 2005 CMP and the Maine Office of the Public Advocate filed with the MPUC a stipulation for an extension of CMP's ARP 2000. The stipulation was also supported by low-income customer advocates, and a coalition of industrial energy customers signed the stipulation agreement. The stipulation maintained the provisions of CMP's ARP 2000 and proposed a three-year extension with four additional items: (i) a 0.5% increase in the scheduled productivity offset of 2.75% for July 2006 and provided for productivity offsets averaging 2% for 2008, 2009 and 2010, (ii) an additional $2.2 million in assistance for low-income customers annually starting in 2006, (iii) CMP agreed to educate its customers on the regional benefits of adjusting usage during peak hours and demand periods and also agreed to limit the promotion of increased usage during specified higher demand periods and (iv) CMP agreed to commit to investing an additional $25 million through 2010 for enhancements to the reliability, safety and security of its distribution system.

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

**CMP Electricity Supply Responsibility** Under Maine statutes, CMP's customers can choose to arrange for competitive energy supply or take default supply under standard-offer service as arranged by the MPUC. The MPUC conducts periodic supply solicitations for standard-offer service by customer class. If the MPUC does not accept any competitive supply bid for a standard offer arrangement, the MPUC can mandate that CMP be a standard-offer provider of electricity supply service for retail customers and CMP would recover all costs of such an arrangement in rates. As of January 2007, the MPUC has approved standard-offer service arrangements for all of CMP's customer classes through competitive solicitation.

The supply prices and terms of the arrangements vary by class, including a laddered three-year arrangement for residential and small commercial customers that solicits one-third of the supply each year and a six-month arrangement for medium and large commercial and industrial customers.

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

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

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

**Nonutility Generation** We expensed approximately $560 million for NUG power in 2006 and we estimate that our combined NUG power purchases will total $568 million in 2007, $392 million in 2008, $229 million in 2009, $84 million in 2010 and $85 million in 2011. CMP and NYSEG continue to seek ways to provide relief to their customers from above-market NUG contracts that state regulators ordered the companies to sign, and which, in 2006, averaged 10.2 cents per kilowatt-hour for CMP and

11.3 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's stranded cost rates and in NYSEG's rates through a nonbypassable wires charge. (See Note 9 to our Consolidated Financial Statements.)

**New England RTO** In March 2004 the FERC issued an order that accepted a six-state New England RTO that CMP participates in and which is operated by ISO-NE and the New England transmission owners. The RTO began operations effective February 1, 2005. As an RTO, ISO-NE is responsible for the independent operation of the regional transmission system and regional wholesale energy market. The transmission owners retain ownership of their transmission facilities and control over their revenue requirements. The FERC also approved both a 50 basis point ROE incentive adder for regional transmission facilities subject to RTO control and a 100 basis point ROE incentive adder for new regional transmission facilities approved as part of the regional planning process. The New England transmission owners appealed the application of the adders to local facilities to the Circuit Court of Appeals for the District of Columbia. Other parties appealed the FERC's decision to grant the adders to regional facilities. On June 30, 2006, the Court denied the appeals and upheld the FERC's decisions. On October 31, 2006, the FERC issued an Opinion and Order on Initial Decision establishing the ROE applicable to the RTO, including CMP's transmission system. The October 31 order adopts a base-level ROE of 10.2 percent, with three adjustments as follows: a 50 basis point incentive for RTO participation; a 100 basis point incentive for new transmission investment; and a 74 basis point adjustment reflecting updated bond data, as applicable to the period commencing with the date of the order. The resulting ROEs for existing regional transmission facilities were 10.7 percent for the period February 1, 2005, through October 31, 2006, and are 11.4 percent for the going-forward period.

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

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

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

The MPUC, among other parties, filed comments opposing the settlement agreement, because the proposal could have an adverse effect on Maine's economy by increasing its generation supply rates, including standard offer rates, by an estimated 5% to 10%. On June 15, 2006, the FERC issued an order accepting the settlement agreement without modification. The MPUC and other parties opposed to the settlement agreement filed a request with the FERC asking it to reconsider its June 15 order. On October 31, 2006, the FERC issued an Order on Rehearing and Clarification denying requests for rehearing and affirming its approval of the settlement agreement. With the FERC's denial of the rehearing requests, the resulting increased costs associated with regional installed capacity have been reflected in Maine consumers' generation supply rates since December 2006. Several parties, including the MPUC, have filed notices of appeal in the US Circuit Court of Appeals, seeking to overturn the FERC's orders approving the settlement agreement. CMP cannot predict the outcome of these proceedings.

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

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

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

## NATURAL GAS DELIVERY RATE OVERVIEW

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

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

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

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

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

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

## NATURAL GAS DELIVERY BUSINESS DEVELOPMENTS

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

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

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

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

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

## NEW ACCOUNTING STANDARDS

The FASB released FIN 48 in July 2006 and issued Statements 157 and 158 in September 2006. See Note 1 to our Consolidated Financial Statements for explanations about these new accounting standards and when they will become or became effective.

## CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

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

| | Total | 2007 | 2008 | 2009 | 2010 | 2011 | After 2011 |
|---|---|---|---|---|---|---|---|
| (Thousands) | | | | | | | |
| **Contractual Obligations** | | | | | | | |
| Long-term debt[1] | $7,521,068 | $497,028 | $318,878 | $365,525 | $467,371 | $407,927 | $5,464,339 |
| Capital lease obligations[1] | 37,116 | 3,486 | 3,486 | 3,513 | 3,513 | 2,791 | 20,327 |
| Operating leases | 87,762 | 13,452 | 13,071 | 11,761 | 11,664 | 10,494 | 27,320 |
| Nonutility generator power purchase obligations | 1,821,553 | 567,815 | 392,057 | 229,209 | 83,586 | 84,927 | 463,959 |
| Nuclear plant obligations | 229,354 | 28,878 | 25,240 | 13,543 | 12,631 | 3,868 | 145,194 |
| Unconditional purchase obligations: | | | | | | | |
| Electric | 2,032,368 | 373,401 | 290,453 | 296,135 | 311,961 | 279,568 | 480,850 |
| Natural gas | 212,320 | 86,017 | 71,276 | 27,284 | 16,589 | 9,864 | 1,290 |
| Pension and other postretirement benefits[2] | 2,252,779 | 184,804 | 193,507 | 203,112 | 213,599 | 225,162 | 1,232,595 |
| Other long-term obligations | 7,179 | 3,727 | 1,621 | 885 | 596 | 267 | 83 |
| **Total Contractual Obligations** | $14,201,499 | $1,758,608 | $1,309,589 | $1,150,967 | $1,121,510 | $1,024,868 | $7,835,957 |

(1) Amounts for long-term debt and capital lease obligations include future interest payments. Future interest payments on variable-rate debt are determined using established rates at December 31, 2006.

(2) Amounts are through 2016 only.

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 Notes 6, 7, 9 and 14 to our Consolidated Financial Statements for additional information regarding our financial commitments at December 31, 2006.

## CRITICAL ACCOUNTING POLICIES

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

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

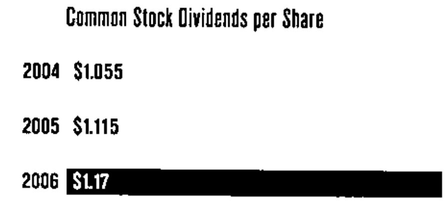
We believe our public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electric and natural gas operations in New York, Maine, Connecticut and Massachusetts; however, we cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC,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

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

**Goodwill and Other Intangible Assets** We do not amortize goodwill or intangible assets with indefinite lives. We test both goodwill and intangible assets with indefinite lives for impairment at least annually and amortize intangible assets with finite lives and review them for impairment. Impairment testing includes various assumptions, primarily the discount rate and forecasted cash flows. We conduct our impairment testing using a range of discount rates representing our marginal, weighted-average cost of capital and a range of assumptions for cash flows. Changes in those assumptions outside of the ranges analyzed could have a significant effect on our determination of an impairment. We had no impairment in 2006 of our goodwill or intangible assets with indefinite lives. (See Note 4 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.

Assumptions are based on our best estimates of future events using historical evidence and long-term trends. Changes in those assumptions, as well as changes in the accounting standards related to pension and postretirement benefit plans, could have a significant effect on our noncash pension income or expense or on our postretirement benefit costs. As of December 31, 2006, we increased the discount rate from 5.50% to 5.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rate was determined by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations. (See Other Market Risk and Note 14 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 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 Note 1 to our Consolidated Financial Statements.)

# Liquidity and Capital Resources

## CASH FLOWS

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

| Year Ended December 31 | 2006 | 2005 | 2004 |
|---|---|---|---|
| (Thousands) | | | |
| **Operating Activities** | | | |
| Net income | **$259,832** | $256,833 | $229,337 |
| Noncash adjustments to net income | **419,196** | 422,635 | 431,700 |
| Changes in working capital | **(198,307)** | (95,256) | (233,246) |
| Other | **(101,227)** | (83,940) | (88,691) |
| **Net Cash Provided by Operating Activities** | **379,494** | 500,272 | 339,100 |
| **Investing Activities** | | | |
| Sale of generation assets | – | – | 453,678 |
| Excess decommissioning funds retained | – | – | 76,593 |
| Utility plant additions | **(408,231)** | (331,294) | (299,263) |
| Current investments available for sale, net | **172,925** | (57,270) | (135,655) |
| Other | **7,547** | 20,133 | 1,600 |
| **Net Cash (Used in) Provided by Investing Activities** | **(227,759)** | (368,431) | 96,953 |
| **Financing Activities** | | | |
| Net issuance of common stock | **(5,764)** | (3,838) | (2,988) |
| Net (repayments of) increase in debt and preferred stock of subsidiaries | **(5,258)** | 30,908 | (333,095) |
| Dividends on common stock | **(167,349)** | (150,367) | (136,374) |
| **Net Cash Used in Financing Activities** | **(178,371)** | (123,297) | (472,457) |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | **(26,636)** | 8,544 | (36,404) |
| **Cash and Cash Equivalents, Beginning of Year** | **120,009** | 111,465 | 147,869 |
| **Cash and Cash Equivalents, End of Year** | **$93,373** | $120,009 | $111,465 |

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

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

Those decreases in cash flow were partially offset by:

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

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

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

Those increases in cash flow were partially offset by:

- Increased expenditures of $40 million to replenish natural gas inventories,
- An increase of $37 million due to higher accounts receivable resulting from higher prices, and
- An increase of $35 million in pension contributions.

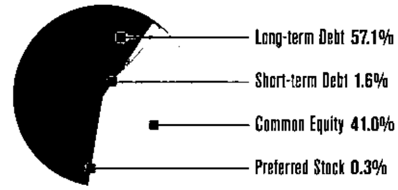
**Investing Activities Cash Flows** Net cash used in investing activities was $228 million in 2006 compared to $368 million in 2005 and net cash provided by investing activities of $97 million in 2004. The $140 million decrease in 2006 was primarily due to the liquidation of current investments available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

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

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

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

Capital Structure




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

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

(1) Includes current portion of long-term debt
(2) Includes notes payable

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

Our equity financing activities during 2006 and early 2007 included:

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

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

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

In July 2006, we redeemed all of our 8 1/4% junior subordinated debt securities at par and expensed approximately $11 million of unamortized expense in July 2006 in connection with the redemption. $10 million of this amount was related to the issuance of the associated trust preferred securities. The redemption was financed by the issuance of $250 million of unsecured long-term debt at 6.75%, due in 2036, and by the issuance of short-term debt. (See Note 6 to our Consolidated Financial Statements.) We settled the hedges we had entered into in connection with the refinancing at a gain of approximately $15 million, which we will amortize over the life of the new debt.

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

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

### AVAILABLE SOURCES OF FUNDING

Energy East is the sole borrower in a revolving credit facility providing maximum borrowings of up to $300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. In June 2006 we extended our two revolving credit facilities for one year. Both facilities now have expiration dates in 2011 and require fees on undrawn borrowing capacity. Two of our operating utilities have uncommitted bilateral credit agreements for a total of $10 million. The two revolving credit facilities and the two bilateral credit agreements provided for consolidated maximum borrowings of $785 million at December 31, 2006, and December 31, 2005.

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

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

## 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 Note 1 to our Consolidated Financial Statements.)

The financial instruments we hold or issue are not for trading or speculative purposes. Our quantitative and qualitative disclosures below relate to the following market risk exposure categories: Interest Rate Risk, Commodity Price Risk and Other Market Risk.

**Interest Rate Risk** We are exposed to risk resulting from interest rate changes on variable-rate debt and commercial paper. We use interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. We record amounts paid and received under those agreements as adjustments to the interest expense of the specific debt issues. After giving effect to those agreements we estimate that, at December 31, 2006, a 1% change in average interest rates would change our annual interest expense for variable-rate debt by about $5 million. Pursuant to its current rate plans, RG&E defers any changes in variable-rate interest expense. (See Notes 6, 7 and 11 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.

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

NYSEG and RG&E offer their retail customers choice in their electricity supply including fixed and variable rate options and an option to purchase electricity supply from an ESCO. During the fourth quarter of 2006, NYSEG's and RG&E's electric customers chose their supply options for 2007. The table below shows the percentages of load that are projected to be served under the various commodity supply options for 2007.

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

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

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

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

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

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

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

**Other Market Risk** Our pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates may cause us to recognize increased or decreased pension income or expense. Our pension income would change by approximately $7 million if our expected return on plan assets were to change by 1/4% and by approximately $6 million if our discount rate were to change by 1/4%. Under RG&E's Electric and Natural Gas Rate Agreements and under NYSEG's natural gas rate plan, we defer changes in pension income resulting from changes in market conditions. (See Note 14 to our Consolidated Financial Statements.)

## Forward-looking Statements

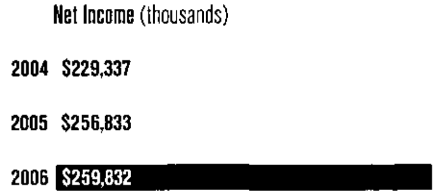
The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. This Annual Report contains certain forward-looking statements that are based upon management's current expectations and information that is currently available. Whenever 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 Market Risk, and also include, among others:

- the deregulation and continued regulatory unbundling of a formerly vertically integrated utility industry,
- our ability to compete in the rapidly changing and competitive electric and/or natural gas utility markets,
- regulatory uncertainty and volatile energy supply prices,
- implementation of NYSEG's Electric Rate Order issued by the NYPSC that has been in effect since January 1, 2007,
- implementation of the Energy Policy Act of 2005,
- increased state and FERC regulation of, among other things, intercompany cost allocations,
- the operation of the NYISO and retroactive NYISO billing adjustments,

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

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




# Results of Operations

## EARNINGS PER SHARE

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

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

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

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

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

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

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

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

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

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

## ENERGY DELIVERY

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

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

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

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

NA – Not applicable

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

| Weather Conditions | 2006 | 2005 | 2004 | Normal |
|---|---|---|---|---|
| **New York** | | | | |
| Heating-degree days | **5,991** | 6,870 | 6,983 | 6,974 |
| (Warmer) colder than prior year | **(13%)** | (2%) | | |
| (Warmer) colder than normal | **(14%)** | (2%) | | |
| Cooling-degree days | **562** | 748 | 324 | 493 |
| (Cooler) warmer than prior year | **(25%)** | 131% | | |
| (Cooler) warmer than normal | **14%** | 52% | | |
| **New England** | | | | |
| Heating-degree days | **5,447** | 6,229 | 6,260 | 6,315 |
| (Warmer) colder than prior year | **(13%)** | (1%) | | |
| (Warmer) colder than normal | **(14%)** | (1%) | | |
| Cooling-degree days | **444** | 506 | 250 | 388 |
| (Cooler) warmer than prior year | **(12%)** | 102% | | |
| (Cooler) warmer than normal | **14%** | 30% | | |

## OPERATING RESULTS FOR THE ELECTRIC DELIVERY BUSINESS

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

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

- An increase of $57 million due to higher commodity prices for retail electric energy sold by NYSEG and RG&E under various commodity options where they provide supply,
- An increase of $60 million in average delivery prices resulting from a transmission rate increase at CMP and higher transition charges for NYSEG and RG&E,

- An increase of $53 million resulting from lower accruals for earnings sharing including $14 million in the first quarter of 2006 for the finalization of actual earnings-sharing amounts for 2005 per NYSEG's and RG&E's annual compliance filings, and
- An increase of $31 million in other revenues primarily for accruals to recover actual purchase power costs, including $25 million for higher Ginna-related costs.

Those increases were partially offset by:

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

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

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

Those increases were partially offset by:

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

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

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

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

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

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

## OPERATING RESULTS FOR THE NATURAL GAS DELIVERY BUSINESS

| | **2006** | 2005 | 2004 |
|---|---|---|---|
| (Thousands) | | | |
| **Operating Revenues** | | | |
| Retail | **$1,676,525** | $1,764,235 | $1,534,900 |
| Wholesale | **563** | 643 | 182 |
| Other | **20,513** | 18,669 | 14,068 |
| **Total Operating Revenues** | **1,697,601** | 1,783,547 | 1,549,150 |
| **Operating Expenses** | | | |
| Natural gas purchased | **1,079,980** | 1,161,059 | 952,806 |
| Other operating and maintenance expenses | **246,727** | 246,339 | 231,182 |
| Depreciation and amortization | **86,728** | 85,050 | 88,998 |
| Other taxes | **95,390** | 98,589 | 93,500 |
| **Total Operating Expenses** | **1,508,825** | 1,591,037 | 1,366,486 |
| **Operating Income** | **$188,776** | $192,510 | $182,664 |

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

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

That decrease was partially offset by:

- An increase of $24 million primarily as a result of higher market prices for natural gas that were passed on to customers,

- An increase of $20 million due to higher base rates for SCG effective January 1, 2006, and
- An increase of $16 million resulting from weather normalization mechanisms.

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

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

Those increases were partially offset by:

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

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

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

Those decreases were partially offset by:

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

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

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

## OPERATING RESULTS FOR THE ENERGY MARKETING BUSINESS

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

| | **2006** | 2005 | 2004 |
|---|---|---|---|
| (Thousands) | | | |
| Electricity sales (MWh) | **4,516** | 5,025 | 4,541 |
| Natural gas sales (Dth) | **7,309** | 10,605 | 11,194 |
| **Operating Revenues** | | | |
| Electric | **$316,221** | $409,473 | $272,268 |
| Natural gas | **81,239** | 109,608 | 91,478 |
| **Total Operating Revenues** | **397,460** | 519,081 | 363,746 |
| **Operating Expenses** | | | |
| Electricity purchased | **300,053** | 397,251 | 261,512 |
| Natural gas purchased | **75,489** | 101,073 | 82,767 |
| Other operating expenses | **12,598** | 13,560 | 11,419 |
| **Total Operating Expenses** | **388,140** | 511,884 | 355,698 |
| **Operating Income** | **$9,320** | $7,197 | $8,048 |

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

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

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

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

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

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

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

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

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

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

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

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

## OTHER ITEMS

| (Thousands) | **2006** | 2005 | 2004 |
|---|---|---|---|
| Other (Income) | **$(46,126)** | $(32,904) | $(35,497) |
| Other Deductions | **$24,578** | $8,858 | $15,803 |
| Interest Charges, net | **$308,824** | $288,897 | $276,890 |
| *Income Taxes on Continuing Operations* | **$155,255** | $169,997 | $251,445 |

**Other (Income) and Other Deductions** (See Note 1 to our Consolidated Financial Statements.)

The changes for 2006 include:

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

The changes for 2005 include:

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

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

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

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

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

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

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

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

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

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

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

We estimate pension income of $43 million for 2007 and expect to contribute between $10 million and $20 million to our pension plans in 2007. (See Note 14 to our Consolidated Financial Statements.)

# ENERGY EAST CORPORATION CONSOLIDATED BALANCE SHEETS

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

The notes on pages 43 through 70 are an integral part of our consolidated financial statements.

# ENERGY EAST CORPORATION CONSOLIDATED BALANCE SHEETS

| December 31 | 2006 | 2005 |
|---|---|---|
| (Thousands) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt | **$260,768** | $326,527 |
| Notes payable | **109,363** | 121,347 |
| Accounts payable and accrued liabilities | **470,325** | 629,158 |
| Interest accrued | **57,243** | 46,522 |
| Taxes accrued | **44,009** | – |
| Deferred income taxes | **–** | 80,984 |
| Unfunded future income tax | **19,664** | – |
| Derivative liabilities | **71,678** | 2,019 |
| Customer refund | **70,770** | 14,698 |
| Other | **209,839** | 171,754 |
| **Total Current Liabilities** | **1,313,659** | 1,393,009 |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | | |
| Accrued removal obligation | **843,273** | 797,544 |
| Deferred income taxes | **105,528** | – |
| Gain on sale of generation assets | **127,674** | 173,216 |
| Pension benefits | **127,330** | 22,798 |
| Natural gas hedges | **–** | 49,205 |
| Other | **93,268** | 124,251 |
| Total regulatory liabilities | **1,297,073** | 1,167,014 |
| Other liabilities | | |
| Deferred income taxes | **1,105,117** | 1,033,287 |
| Nuclear plant obligations | **202,963** | 234,907 |
| Pension and other postretirement benefits | **530,838** | 428,691 |
| Environmental remediation costs | **168,949** | 166,462 |
| Derivative liability | **21,871** | 24,887 |
| Other | **306,283** | 475,081 |
| Total other liabilities | **2,336,021** | 2,363,315 |
| **Total Regulatory and Other Liabilities** | **3,633,094** | 3,530,329 |
| Debt owed to subsidiary holding solely parent debentures | **–** | 355,670 |
| Other long-term debt | **3,726,709** | 3,311,395 |
| Total long-term debt | **3,726,709** | 3,667,065 |
| **Total Liabilities** | **8,673,462** | 8,590,403 |
| **Commitments and Contingencies** | | |
| **Preferred Stock of Subsidiaries** | | |
| Redeemable solely at the option of subsidiaries | **24,592** | 24,631 |
| **Common Stock Equity** | | |
| Common stock ($.01 par value, 300,000 shares authorized, 147,907 shares outstanding at December 31, 2006, and 147,701 shares outstanding at December 31, 2005) | **1,480** | 1,478 |
| Capital in excess of par value | **1,505,795** | 1,489,256 |
| Retained earnings | **1,382,461** | 1,294,580 |
| Accumulated other comprehensive income (loss) | **(23,779)** | 89,085 |
| Treasury stock, at cost (52 shares at December 31, 2006, and 53 shares at December 31, 2005) | **(1,610)** | (1,725) |
| **Total Common Stock Equity** | **2,864,347** | 2,872,674 |
| **Total Liabilities and Stockholders' Equity** | **$11,562,401** | $11,487,708 |

The notes on pages 43 through 70 are an integral part of our consolidated financial statements.

# ENERGY EAST CORPORATION CONSOLIDATED STATEMENTS OF INCOME

| Year Ended December 31 | 2006 | 2005 | 2004 |
|---|---|---|---|
| (Thousands, except per share amounts) | | | |
| **Operating Revenues** | | | |
| Utility | **$4,720,638** | $4,753,105 | $4,330,472 |
| Other | **510,027** | 545,438 | 426,220 |
| **Total Operating Revenues** | **5,230,665** | 5,298,543 | 4,756,692 |
| **Operating Expenses** | | | |
| Electricity purchased and fuel used in generation | | | |
| Utility | **1,467,068** | 1,457,746 | 1,321,081 |
| Other | **353,402** | 360,621 | 249,330 |
| Natural gas purchased | | | |
| Utility | **1,079,980** | 1,161,059 | 952,806 |
| Other | **79,472** | 107,755 | 77,508 |
| Other operating expenses | **796,350** | 797,015 | 799,460 |
| Maintenance | **218,499** | 197,704 | 173,191 |
| Depreciation and amortization | **282,568** | 277,217 | 292,457 |
| Other taxes | **249,834** | 246,271 | 252,860 |
| Gain on sale of generation assets | **–** | – | (340,739) |
| Deferral of asset sale gain | **–** | – | 228,785 |
| **Total Operating Expenses** | **4,527,173** | 4,605,388 | 4,006,739 |
| **Operating Income** | **703,492** | 693,155 | 749,953 |
| **Other (Income)** | **(46,126)** | (32,904) | (35,497) |
| **Other Deductions** | **24,578** | 8,858 | 15,803 |
| **Interest Charges, Net** | **308,824** | 288,897 | 276,890 |
| **Preferred Stock Dividends of Subsidiaries** | **1,129** | 1,474 | 3,691 |
| **Income From Continuing Operations Before Income Taxes** | **415,087** | 426,830 | 489,066 |
| **Income Taxes** | **155,255** | 169,997 | 251,445 |
| **Income From Continuing Operations** | **259,832** | 256,833 | 237,621 |
| **Discontinued Operations** | | | |
| Loss from discontinued operations (including loss on disposal of $(7,565) in 2004) | **–** | – | (7,109) |
| Income taxes | **–** | – | 1,175 |
| **Loss From Discontinued Operations** | **–** | – | (8,284) |
| **Net Income** | **$259,832** | $256,833 | $229,337 |
| **Earnings per Share From Continuing Operations, basic** | **$1.77** | $1.75 | $1.63 |
| **Earnings per Share From Continuing Operations, diluted** | **$1.76** | $1.74 | $1.62 |
| **Loss per Share From Discontinued Operations, basic and diluted** | **–** | – | $(.06) |
| **Earnings per Share, basic** | **$1.77** | $1.75 | $1.57 |
| **Earnings per Share, diluted** | **$1.76** | $1.74 | $1.56 |
| **Average Common Shares Outstanding, basic** | **146,962** | 146,964 | 146,305 |
| **Average Common Shares Outstanding, diluted** | **147,717** | 147,474 | 146,713 |

The notes on pages 43 through 70 are an integral part of our consolidated financial statements.

# ENERGY EAST CORPORATION CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year Ended December 31 | 2006 | 2005 | 2004 |
|---|---|---|---|
| (Thousands) | | | |
| **Operating Activities** | | | |
| Net income | **$259,832** | $256,833 | $229,337 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation and amortization | **418,152** | 382,873 | 377,181 |
| Income taxes and investment tax credits deferred, net | **31,125** | 69,729 | 83,327 |
| Income taxes related to gain on sale of generation assets | **-** | - | 111,954 |
| Gain on sale of generation assets | **-** | - | (340,739) |
| Deferral of asset sale gain | **-** | - | 228,785 |
| Pension income | **(30,081)** | (29,967) | (28,808) |
| Changes in current operating assets and liabilities | | | |
| Accounts receivable and unbilled revenues, net | **16,026** | (107,308) | (70,067) |
| Inventory | **1,437** | (86,735) | (43,579) |
| Prepayments and other current assets | **(65,466)** | (36,373) | 1,326 |
| Accounts payable and accrued liabilities | **(140,521)** | 198,932 | 91,527 |
| Taxes accrued | **11,148** | 1,376 | (91,840) |
| Interest accrued | **10,721** | 3,053 | (5,520) |
| Customer refund | **(15,485)** | (25,329) | (58,219) |
| Other current liabilities | **(15,767)** | 11,448 | (37,213) |
| Pension contributions | **(400)** | (54,320) | (19,661) |
| Changes in other assets | | | |
| RG&E nuclear plant dispute settlement | **(33,655)** | (125) | (141) |
| Other | **(1,722)** | (76,167) | (82,733) |
| Changes in other liabilities | | | |
| RG&E generation related ASGA charges | **(55,420)** | (25,798) | (31,064) |
| Other | **(10,430)** | 18,150 | 25,247 |
| **Net Cash Provided by Operating Activities** | **379,494** | 500,272 | 339,100 |
| **Investing Activities** | | | |
| Sale of generation assets | **-** | - | 453,678 |
| Excess decommissioning funds retained | **-** | - | 76,593 |
| Utility plant additions | **(408,231)** | (331,294) | (299,263) |
| Other property additions | **(3,817)** | (2,507) | (5,623) |
| Other property sold | **342** | 25,704 | 6,161 |
| Maturities of current investments available for sale | **1,054,665** | 1,635,005 | 994,680 |
| Purchases of current investments available for sale | **(881,740)** | (1,692,275) | (1,130,335) |
| Investments | **11,022** | (3,064) | 1,062 |
| **Net Cash (Used in) Provided by Investing Activities** | **(227,759)** | (368,431) | 96,953 |
| **Financing Activities** | | | |
| Issuance of common stock | **343** | 2,654 | 3,083 |
| Repurchase of common stock | **(6,107)** | (6,492) | (6,071) |
| Issuance of first mortgage bonds | **-** | 70,000 | - |
| Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums | **(39)** | (47,260) | (201,005) |
| Derivative activity | **22,899** | - | - |
| Long-term note issuances | **652,137** | 208,893 | 212,975 |
| Long-term note repayments | **(667,263)** | (120,061) | (249,025) |
| Notes payable three months or less, net | **(12,873)** | (85,967) | (92,932) |
| Notes payable issuances | **1,436** | 1,251 | 4,000 |
| Notes payable repayments | **(547)** | (408) | (13,000) |
| Book overdraft | **(1,008)** | 4,460 | 5,892 |
| Dividends on common stock | **(167,349)** | (150,367) | (136,374) |
| **Net Cash Used in Financing Activities** | **(178,371)** | (123,297) | (472,457) |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | **(26,636)** | 8,544 | (36,404) |
| **Cash and Cash Equivalents, Beginning of Year** | **120,009** | 111,465 | 147,869 |
| **Cash and Cash Equivalents, End of Year** | **$93,373** | $120,009 | $111,465 |

The notes on pages 43 through 70 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 Shares | $.01 Par Value Amount | Capital in Excess of Par Value | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Deferred Compensation | Treasury Stock | Total |
|---|---|---|---|---|---|---|---|---|
| **Balance, January 1, 2004** | 146,262 | $1,463 | $1,456,220 | $1,126,457 | $(11,214) | $(2,820) | $(364) | $2,569,742 |
| Net income | | | | 229,337 | | | | 229,337 |
| Other comprehensive income, net of tax | | | | | (32,347) | | | (32,347) |
| Comprehensive income | | | | | | | | 196,990 |
| Common stock dividends declared ($1.055 per share) | | | | (154,261) | | | | (154,261) |
| *Common stock issued –* Investor Services Program | 872 | 9 | 20,962 | | | | | 20,971 |
| Common stock repurchased | (250) | | | | | | (6,071) | (6,071) |
| Common stock issued – restricted stock plan | 242 | | (132) | | | (5,784) | 5,916 | – |
| Amortization of deferred compensation under restricted stock plan | | | | | | 3,584 | | 3,584 |
| Treasury stock transactions, net | (8) | | 94 | | | | (164) | (70) |
| Amortization of capital stock issue expense, net | | | 374 | | | | | 374 |
| **Balance, December 31, 2004** | 147,118 | 1,472 | 1,477,518 | 1,201,533 | (43,561) | (5,020) | (683) | 2,631,259 |
| Net income | | | | 256,833 | | | | 256,833 |
| Other comprehensive income, net of tax | | | | | 132,646 | | | 132,646 |
| Comprehensive income | | | | | | | | 389,479 |
| Common stock dividends declared ($1.115 per share) | | | | (163,786) | | | | (163,786) |
| Common stock issued – Investor Services Program | 607 | 6 | 16,066 | | | | | 16,072 |
| Common stock repurchased | (250) | | | | | | (6,492) | (6,492) |
| Common stock issued – restricted stock plan | 265 | | (6,404) | | | (451) | 6,855 | – |
| Amortization of deferred compensation under restricted stock plan | | | | | | 5,471 | | 5,471 |
| Treasury stock transactions, net | (39) | | 1,702 | | | | (1,405) | 297 |
| Amortization of capital stock issue 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 |

The notes on pages 43 through 70 are an integral part of our consolidated financial statements.

## NOTE 1 Significant Accounting Policies

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Other (Income) and Other Deductions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## NOTE 2 Sale of Ginna

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

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

## NOTE 3 Impairment of Assets and Disposal of Other Businesses

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

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

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

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

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

The results of discontinued operations of the businesses sold were:

| Year Ended December 31 | 2004 |
|---|---|
| (Thousands) | |
| **Component of Energy East Solutions, Inc.** | |
| Revenues | $48,634 |
| Loss from operations of discontinued business | $(859) |
| Income taxes (benefits) | (142) |
| Loss from discontinued operations | $(717) |
| **Certain Divisions of The Union Water-Power Company** | |
| Revenues | $13,156 |
| Loss from operations of discontinued business | $(6,250) |
| Income taxes | 151 |
| Loss from discontinued operations | $(6,401) |
| **Griffith Oil Co., Inc.** | |
| Revenues | – |
| Loss from operations of discontinued business | – |
| Income taxes | $1,166 |
| Loss from discontinued operations | $(1,166) |
| **Totals for discontinued operations** | |
| Total revenues | $61,790 |
| Total loss from operations of discontinued businesses | $(7,109) |
| Total income taxes | 1,175 |
| **Total loss from discontinued operations** | $(8,284) |

## NOTE 4 Goodwill and Other Intangible Assets

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

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

| December 31 | 2006 | 2005 |
|---|---|---|
| (Thousands) | | |
| Electric delivery | **$845,296** | $844,491 |
| Natural gas delivery | **677,080** | 676,588 |
| Other | **3,672** | 4,274 |
| Total | **$1,526,048** | $1,525,353 |

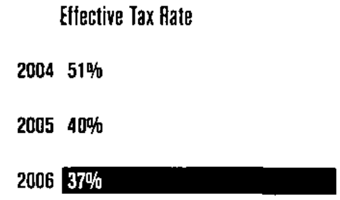
**Other Intangible Assets** Our unamortized intangible assets had a carrying amount of $2 million at December 31, 2006, and $19 million at December 31, 2005, and primarily consisted of franchise costs in 2006 and pension assets in 2005. Our amortized intangible assets had a gross carrying amount of $27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

## NOTE 5 Income Taxes

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

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

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




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

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

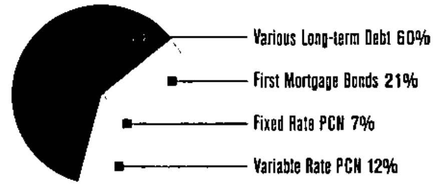
| | 2006 | 2005 |
|---|---|---|
| (Thousands) | | |
| **Current Deferred Income Tax Assets (Liabilities)** | | |
| Derivative assets and liabilities | **$27,076** | $(110,390) |
| Other | **66,111** | 29,406 |
| **Total Current Deferred Income Tax Assets (Liabilities)** | **$93,187** | $(80,984) |
| **Noncurrent Deferred Income Tax Liabilities** | | |
| *Depreciation* | **$993,499** | $946,155 |
| Unfunded future income taxes | **103,385** | 136,059 |
| Accumulated deferred ITC | **35,320** | 38,604 |
| Deferred (gain) on sale of generation assets | **(31,718)** | (49,715) |
| Pension | **246,955** | 170,541 |
| Statement 106 postretirement benefits | **(119,115)** | (135,205) |
| Derivative (liabilities) | **(4,536)** | (11,132) |
| Other | **(13,548)** | (75,502) |
| **Total Noncurrent Deferred Income Tax Liabilities** | **1,210,242** | 1,019,805 |
| Valuation allowance | **403** | – |
| Less amounts classified as regulatory liabilities | | |
| Deferred income taxes | **105,528** | (13,482) |
| **Noncurrent Deferred Income Tax Liabilities** | **$1,105,117** | $1,033,287 |
| Deferred tax assets | **$262,103** | $300,960 |
| Deferred tax liabilities | **1,379,158** | 1,401,749 |
| **Net Accumulated Deferred Income Tax Liability** | **$1,117,055** | $1,100,789 |

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

## NOTE 6 Long-term Debt

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

Other Long-term Debt




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

| Company | | Interest Rates | Maturity | Amount (Thousands) 2006 | 2005 |
|---|---|---|---|---|---|
| | **First mortgage bonds**[(1)] | | | | |
| RG&E | Series B, TT, UU & VV | 5.84% - 7.60% | 2008 - 2033 | **$511,000** | $511,000 |
| RG&E | PCN 2004 Series A & B | 3.60% - 3.85% | 2032 | **60,500** | 60,500 |
| SCG | Medium Term Note I, II & III | 4.57% - 7.95% | 2007 - 2035 | **219,000** | 224,000 |
| SCG | Series W | 8.93% | 2021 | **25,000** | 25,000 |
| Berkshire Gas | Series P | 10.06% | 2019 | **10,000** | 10,000 |
| Total first mortgage bonds | | | | **825,500** | 830,500 |
| | **Unsecured pollution control notes, fixed** | | | | |
| NYSEG | 1994 Series A & E | 5.90% - 6.00% | 2006 | - | 37,000 |
| NYSEG | 1985 Series A, B & D | 4.00% - 4.10% | 2015 | **132,000** | 132,000 |
| NYSEG | 2004 Series C | 3.245% | 2034 | **100,000** | 100,000 |
| RG&E | 1998 Series A | 5.95% | 2033 | **25,500** | 25,500 |
| CMP | Industrial Development Authority of the state of New Hampshire Notes | 5.375% | 2014 | **19,500** | 19,500 |
| Total unsecured pollution control notes, fixed | | | | **277,000** | 314,000 |
| | **Unsecured pollution control notes, variable** | | | | |
| NYSEG | 2006 Series A | 3.75% | 2024 | **12,000** | – |
| NYSEG | 2005 Series A | 3.75% | 2026 | **65,000** | 65,000 |
| NYSEG | 2004 Series A & B | 3.80% - 3.85% | 2027 - 2028 | **104,000** | 104,000 |
| NYSEG | 1994 Series B, C, D1 & D2 | 3.50% - 3.60% | 2029 | **175,000** | 175,000 |
| RG&E | 1997 Series A, B & C | 3.38% - 3.50% | 2032 | **101,900** | 101,900 |
| TEN Cos | Industrial Revenue Variable Rate Demand Bonds | 3.92% | 2025 - 2030 | **14,900** | 14,900 |
| Total unsecured pollution control notes, variable | | | | **472,800** | 460,800 |
| | ***Various long-term debt*** | | | | |
| Energy East | Unsecured Note | 5.75% | 2006 | - | 232,350 |
| Energy East | Unsecured Note | 8.05% | 2010 | **200,000** | 200,000 |
| Energy East | Unsecured Note | 6.75% | 2012 | **400,000** | 400,000 |
| Energy East | Unsecured Note | 6.75% | 2033 | **200,000** | 200,000 |
| Energy East | Unsecured Notes | 6.75% | 2036 | **500,000** | - |
| NYSEG | Unsecured Notes | 4.375% - 5.75% | 2007 - 2023 | **550,000** | 450,000 |
| CMP | Series E & F Medium Term Notes | 4.25% - 7.00% | 2007 - 2035 | **310,700** | 310,700 |
| CNG | Medium Term Notes Series A, B & C | 5.63% - 9.10% | 2007 - 2035 | **149,000** | 149,000 |
| Berkshire Gas | Unsecured Notes | 4.76% - 9.60% | 2011 - 2021 | **36,000** | 36,000 |
| Energetix | Promissory Note | 8.50% | 2007 | **3,509** | 3,509 |
| TEN Cos | Senior Secured Term Notes | 6.90% - 6.99% | 2009 - 2010 | **30,000** | 35,000 |
| NORVARCO | Promissory and Senior Note | 7.05% - 10.48% | 2020 | **16,373** | 17,556 |
| Total various long-term debt | | | | **2,395,582** | 2,034,115 |
| Obligations under *capital leases* | | | | **25,187** | 26,855 |
| Unamortized premium and discount on debt, net | | | | **(8,592)** | (28,348) |
| | | | | **3,987,477** | 3,637,922 |
| Less debt due within one year, included in current liabilities | | | | **260,768** | 326,527 |
| **Total** | | | | **$3,726,709** | $3,311,395 |

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

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

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

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

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

## NOTE 7 Bank Loans and Other Borrowings

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

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

In our revolving credit facility we covenant not to permit, without the consent of the lender, our ratio of consolidated indebtedness to consolidated total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to consolidated total capitalization, we have amended the facility to exclude from consolidated net worth the balance of 'Accumulated other comprehensive income (loss)' as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness Energy East may maintain. Continued unremedied failure to comply with those covenants for 15 days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity. Our ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit facility was 0.58 to 1.00 at December 31, 2006. We are not in default, and no condition exists that is likely to create a default, under the facility.

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

## NOTE 8 Preferred Stock Redeemable Solely at the Option of Subsidiaries

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

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

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

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

| Subsidiary | Date | Series | Amount (Thousands) |
|---|---|---|---|
| Berkshire Gas | September 16, 2004 | 4.80% | $5.6 |
| Berkshire Gas | September 15, 2005 | 4.80% | $39.9 |
| Berkshire Gas | September 15, 2006 | 4.80% | $39.3 |
| RG&E | May 5, 2004 | 4.00% F | $12,000 |
| RG&E | May 5, 2004 | 4.10% H | $8,000 |
| RG&E | May 5, 2004 | 4.75% I | $6,000 |
| RG&E | May 5, 2004 | 4.10% J | $5,000 |
| RG&E | May 5, 2004 | 4.95% K | $6,000 |
| RG&E | May 5, 2004 | 4.55% M | $10,000 |
| CMP | June 10, 2005 | 3.50% | $22,000 |

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

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

## NOTE 9 Commitments and Contingencies

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

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

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

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

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

## NOTE 10 Environmental Liability and Nuclear Decommissioning

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

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

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

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

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

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

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

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

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

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

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

## NOTE 11 Fair Value of Financial Instruments

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

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

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

## NOTE 12 Share-Based Compensation

As of December 31, 2006, we have two share-based compensation plans, which are described below. The total compensation cost recognized in income for those plans for the years ended December 31 was: \$12.0 million for 2006, \$4.1 million for 2005 and \$21.1 million for 2004. The total income tax benefit recognized in income for the share-based compensation arrangements for the years ended December 31 was: \$4.8 million for 2006, \$1.7 million for 2005 and \$8.4 million for 2004.

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

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

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

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

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

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

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

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

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

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

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

## NOTE 13 Accumulated Other Comprehensive Income (Loss)

| (Thousands) | Balance January 1 2004 | 2004 Change | Balance December 31 2004 | 2005 Change | Balance December 31 2005 | 2006 Change[1] | Balance December 31 2006 |
|---|---|---|---|---|---|---|---|
| Unrealized gains (losses) on investments: | | | | | | | |
| Unrealized holding gains during period, net of income tax (expense) of $(316) for 2004, $(210) for 2005 and $(964) for 2006 | | $491 | | $333 | | $1,454 | |
| Net unrealized (losses) gains on investments | $(896) | 491 | $(405) | 333 | $(72) | 1,454 | $1,382 |
| Minimum pension liability adjustment, net of income tax benefit (expense) of $8,114 for 2004, $8,674 for 2005 and $(43,850) for 2006 | (40,120) | (7,915) | (48,035) | (16,983) | (65,018) | 65,018 | – |
| Adjustment to initially apply Statement 158 for nonqualified plans, net of income tax benefit of $11,153 for 2006 | | | | | | (16,817) | (16,817) |
| Unrealized gains (losses) on derivatives qualified as hedges: | | | | | | | |
| Unrealized gains during period on derivatives qualified as hedges, net of income tax (expense) benefit of $(5,061) for 2004, $(107,041) for 2005 and $112,637 for 2006 | | 8,964 | | 167,352 | | (174,459) | |
| Reclassification adjustment for (gains) included in net income, net of income tax expense (benefit) of $22,037 for 2004, $11,987 for 2005 and $(7,843) for 2006 | | (33,887) | | (18,056) | | 11,940 | |
| Net unrealized gains (losses) on derivatives qualified as hedges[2] | 29,802 | (24,923) | 4,879 | 149,296 | 154,175 | (162,519) | (8,344) |
| **Accumulated Other Comprehensive Income (Loss)** | $(11,214) | $(32,347) | $(43,561) | $132,646 | $89,085 | $(112,864) | $(23,779) |

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

(2) See Risk management in Note 1.

## NOTE 14 Retirement Benefits

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

### Obligations and funded status

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **2006** | 2005 | **2006** | 2005 |
| (Thousands) | | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | **$2,366,748** | $2,254,209 | **$536,997** | $559,977 |
| Service cost | **37,443** | 35,379 | **5,852** | 5,775 |
| Interest cost | **127,197** | 127,785 | **29,319** | 30,719 |
| Plan participants' contributions | **–** | – | **25** | 642 |
| Plan amendments | **–** | 418 | **247** | – |
| Actuarial loss (gain) | **(93,685)** | 81,844 | **(5,728)** | (23,686) |
| Benefits paid | **(135,710)** | (132,887) | **(38,275)** | (36,430) |
| Federal subsidy on benefits paid | **–** | – | **2,006** | – |
| Benefit obligation at December 31 | **$2,301,993** | $2,366,748 | **$530,443** | $536,997 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | **$2,584,525** | $2,475,494 | **$31,128** | $32,105 |
| Actual return on plan assets | **366,210** | 187,449 | **3,306** | 1,516 |
| Employer contributions | **400** | 54,469 | **28,125** | 26,463 |
| Plan participants' contributions | **–** | – | **25** | 642 |
| Benefits paid | **(135,710)** | (132,887) | **(25,283)** | (29,598) |
| Fair value of plan assets at December 31 | **$2,815,425** | $2,584,525 | **$37,301** | $31,128 |
| Funded status at December 31 | **$513,432** | $217,777 | **$(493,142)** | $(505,869) |
| Unrecognized net actuarial loss[1] | | $481,244 | | $66,349 |
| Unrecognized prior service cost (benefit)[1] | | 42,810 | | (36,770) |
| Unrecognized net transition obligation[1] | | – | | 47,599 |
| Total unrecognized amounts | | $524,054 | | $77,178 |
| Prepaid (accrued) benefit cost | | $741,831 | | $(428,691) |

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

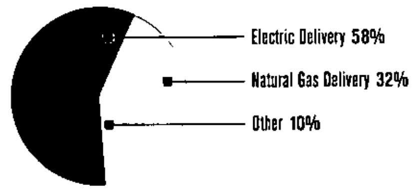
Our pension benefits plan assets are held in a master trust with a trustee and our postretirement benefits plan assets are held with two trustees in multiple VEBA and 401(h) arrangements. Those assets are invested among and within various asset classes in order to achieve sufficient diversification in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

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

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

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

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

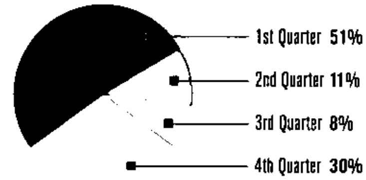



## NOTE 15 Segment Information

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

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

Quarterly Earnings per Share, basic




## NOTE 16 Quarterly Financial Information (Unaudited)

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

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

PRICEWATERHOUSECOOPERS

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

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

## Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of changes in common stock equity present fairly, in all material respects, the financial position of Energy East Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

## Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Annual Report on Internal Control Over Financial Reporting appearing on page 73, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 28, 2007

## Management's Annual Report on Internal Control Over Financial Reporting

Energy East's management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, an evaluation was conducted of the effectiveness of the internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by The Committee of Sponsoring Organizations of the Treadway Commission. Based on Energy East's evaluation under the framework in *Internal Control – Integrated Framework*, management concluded that Energy East's internal control over financial reporting was effective as of December 31, 2006.

Energy East management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page 71.

## Required Certifications

On July 6, 2006, Energy East submitted to the New York Stock Exchange its Annual Chief Executive Officer Certification under Section 303A of the New York Stock Exchange Corporate Governance Rules.

Energy East filed with the Securities and Exchange Commission the Certifications of its Chief Executive Officer and Chief Financial Officer as required under Section 302 of the Sarbanes-Oxley Act of 2002. The certifications were filed as Exhibits 31-1 and 31-2 to Energy East's Form 10-K for the fiscal year ended December 31, 2006, dated February 28, 2007.

# GLOSSARY

## Abbreviations or acronyms frequently used in this report:

**ALJ** Administrative Law Judge

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

**ARP 2000** Alternative Rate Plan 2000

**ASGA** Asset Sale Gain Account

**Bechtel** Bechtel Power Corporation

**CGG** Constellation Generation Group, LLC

**Connecticut Yankee** Connecticut Yankee Atomic Power Company

**DOE** United States Department of Energy

**DPUC** Connecticut Department of Public Utility Control

**DTE** Massachusetts Department of Telecommunications and Energy

**Dth** dekatherm

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

**EPA** United States Environmental Protection Agency

**EPS** earnings per share

**ESCO** energy service company

**FASB** Financial Accounting Standards Board

**FERC** Federal Energy Regulatory Commission

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

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

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

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

**IRP** Incentive Rate Plan

**ISO-NE** ISO New England Inc.

**ITC** investment tax credit

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

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

**MPUC** Maine Public Utilities Commission

**MW, MWh** megawatt, megawatt-hour

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

**NMP2** Nine Mile Point 2 nuclear generating station

**NRC** United States Nuclear Regulatory Commission

**NUG** nonutility generator

**NYISO** New York Independent System Operator

**NYPA** New York Power Authority

**NYPSC** New York State Public Service Commission

**NYSDEC** New York State Department of Environmental Conservation

**OCC** The Office of Consumer Counsel in the State of Connecticut

**OPEB** other post-employment benefits

**PCN** Pollution control notes

**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** United States Securities and Exchange Commission

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

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

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

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

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

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

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

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

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

**TCC** transmission congestion contract

**VEBA** voluntary employees' beneficiary association

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

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

## Abbreviations for the Energy East companies mentioned in this report:

**Berkshire Energy** Berkshire Energy Resources

**Berkshire Gas** The Berkshire Gas Company

**Cayuga Energy** Cayuga Energy, Inc.

**CMP** Central Maine Power Company

**CMP Group** CMP Group, Inc.

**CNE** Connecticut Energy Corporation

**CNG** Connecticut Natural Gas Corporation

**CTG Resources** CTG Resources, Inc.

**Energetix** Energetix, Inc.

**Energy East, the company, we, our** or **us** Energy East Corporation

**MNG** Maine Natural Gas Corporation

**NYSEG** New York State Electric & Gas Corporation

**RG&E** Rochester Gas and Electric Corporation

**RGS Energy** RGS Energy Group, Inc.

**SCG** The Southern Connecticut Gas Company

**SGF** South Glens Falls Energy, LLC

**TEN Cos** TEN Companies, Inc.

**The Energy Network** The Energy Network, Inc.

# SELECTED FINANCIAL DATA

| Year Ended December 31 | 2006 | 2005 | 2004 | 2003 | 2002[1] |
|---|---|---|---|---|---|
| (Thousands, except per share amounts) | | | | | |
| **Operating Revenues** | | | | | |
| Utility | **$4,720,638** | $4,753,105 | $4,330,472 | $4,220,822 | $3,600,786 |
| Other | **510,027** | 545,438 | 426,220 | 293,668 | 177,240 |
| **Total Operating Revenues** | **5,230,665** | 5,298,543 | 4,756,692 | 4,514,490 | 3,778,026 |
| **Operating Expenses** | | | | | |
| Electricity purchased and fuel used in generation | | | | | |
| Utility | **1,467,068** | 1,457,746 | 1,321,081 | 1,192,397 | 1,192,829 |
| Other | **353,402** | 360,621 | 249,330 | 145,972 | 83,258 |
| Natural gas purchased | | | | | |
| Utility | **1,079,980** | 1,161,059 | 952,806 | 862,452 | 525,036 |
| Other | **79,472** | 107,755 | 77,508 | 77,012 | 44,758 |
| Other operating expenses | **796,350** | 797,015 | 799,460 | 813,133 | 667,190 |
| Maintenance | **218,499** | 197,704 | 173,191 | 203,043 | 160,291 |
| Depreciation and amortization | **282,568** | 277,217 | 292,457 | 299,430 | 240,306 |
| Other taxes | **249,834** | 246,271 | 252,860 | 269,238 | 229,158 |
| Restructuring expenses | **–** | – | – | – | 40,567 |
| Gain on sale of generation assets | **–** | – | (340,739) | – | – |
| Deferral of asset sale gain | **–** | – | 228,785 | – | – |
| **Total Operating Expenses** | **4,527,173** | 4,605,388 | 4,006,739 | 3,862,677 | 3,183,393 |
| **Operating Income** | **703,492** | 693,155 | 749,953 | 651,813 | 594,633 |
| **Writedown of Investment** | **–** | – | – | – | 12,209 |
| **Other (Income)** | **(46,126)** | (32,904) | (35,497) | (17,226) | (25,332) |
| **Other Deductions** | **24,578** | 8,858 | 15,803 | 28,395 | 29,260 |
| **Interest Charges, Net** | **308,824** | 288,897 | 276,890 | 284,482 | 256,161 |
| **Preferred Stock Dividends of Subsidiaries** | **1,129** | 1,474 | 3,691 | 19,009 | 32,129 |
| **Income From Continuing Operations Before Income Taxes** | **415,087** | 426,830 | 489,066 | 337,153 | 290,206 |
| **Income Taxes** | **155,255** | 169,997 | 251,445 | 128,663 | 100,277 |
| **Income From Continuing Operations** | **259,832** | 256,833 | 237,621 | 208,490 | 189,929 |
| **Discontinued Operations** | | | | | |
| Loss from discontinued operations (including loss on disposal of $(7,565) in 2004) | **–** | – | (7,109) | (12,032) | (3,079) |
| Income taxes (benefits) | **–** | – | 1,175 | (13,988) | (1,753) |
| **(Loss) Income From Discontinued Operations** | **–** | – | (8,284) | 1,956 | (1,326) |
| **Net Income** | **259,832** | 256,833 | 229,337 | 210,446 | 188,603[2] |
| **Common Stock Dividends** | **171,951** | 163,786 | 154,261 | 145,417 | 125,456 |
| **Retained Earnings Increase** | **$87,881** | $93,047 | $75,076 | $65,029 | $63,147 |
| **Average Common Shares Outstanding, basic** | **146,962** | 146,964 | 146,305 | 145,535 | 131,117 |
| **Earnings per Share From Continuing Operations, basic** | **$1.77** | $1.75 | $1.63 | $1.43 | $1.45[2] |
| **Earnings per Share From Continuing Operations, diluted** | **$1.76** | $1.74 | $1.62 | $1.43 | $1.45[2] |
| **Earnings per Share, basic** | **$1.77** | $1.75 | $1.57 | $1.45 | $1.44[2] |
| **Earnings per Share, diluted** | **$1.76** | $1.74 | $1.56 | $1.44 | $1.44[2] |
| **Dividends Declared per Share** | **$1.17** | $1.115 | $1.055 | $1.00 | $.96 |
| **Book Value per Share of Common Stock at Year End** | **$19.37** | $19.45 | $17.89 | $17.57 | $16.97 |
| **Utility Capital Spending** | **$408,231** | $331,294 | $299,263 | $289,320 | $229,387 |
| **Total Assets** | **$11,562,401** | $11,487,708 | $10,796,622 | $11,330,441 | $10,944,347 |
| **Long-term Obligations, Capital Leases and Redeemable Preferred Stock** | **$3,726,709** | $3,667,065 | $3,797,685 | $4,017,846 | $3,721,959 |

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

# ENERGY DISTRIBUTION STATISTICS

| | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| **Electric Deliveries** | | | | | |
| (Megawatt-hours) | | | | | |
| Residential | **12,125** | 12,601 | 11,848 | 11,676 | 10,226 |
| Commercial | **9,630** | 9,805 | 9,480 | 9,266 | 8,019 |
| Industrial | **7,149** | 7,334 | 7,446 | 7,412 | 6,694 |
| Other | **2,229** | 2,279 | 2,245 | 2,239 | 1,930 |
| **Total Retail** | **31,133** | 32,019 | 31,019 | 30,593 | 26,869 |
| Wholesale | **9,317** | 9,466 | 7,855 | 5,734 | 5,330 |
| **Total Electric Deliveries** | **40,450** | 41,485 | 38,874 | 36,327 | 32,199 |
| **Electric Revenues** | | | | | |
| Residential | **$1,267,525** | $1,284,606 | $1,163,887 | $1,204,228 | $1,073,586 |
| Commercial | **556,635** | 536,779 | 565,976 | 667,802 | 609,165 |
| Industrial | **272,163** | 268,647 | 284,608 | 344,352 | 313,622 |
| Other | **157,680** | 160,073 | 177,029 | 191,756 | 175,130 |
| **Total Retail** | **2,254,003** | 2,250,105 | 2,191,500 | 2,408,138 | 2,171,503 |
| Wholesale | **554,300** | 568,746 | 402,122 | 233,331 | 190,090 |
| Other | **214,734** | 150,707 | 187,700 | 117,226 | 206,654 |
| **Total Electric Revenues** | **$3,023,037** | $2,969,558 | $2,781,322 | $2,758,695 | $2,568,247 |
| **Natural Gas Deliveries** | | | | | |
| (Dekatherms) | | | | | |
| Residential | **70,636** | 80,049 | 82,574 | 85,401 | 62,748 |
| Commercial | **23,904** | 26,733 | 26,493 | 25,938 | 21,190 |
| Industrial | **3,529** | 3,951 | 4,062 | 3,458 | 2,934 |
| Other | **12,892** | 11,020 | 11,276 | 11,301 | 14,507 |
| Transportation of customer-owned natural gas | **77,318** | 82,924 | 84,039 | 86,647 | 80,480 |
| **Total Retail** | **188,279** | 204,677 | 208,444 | 212,745 | 181,859 |
| Wholesale | **111** | 883 | 1,593 | 5,360 | 7,074 |
| **Total Natural Gas Deliveries** | **188,390** | 205,560 | 210,037 | 218,105 | 188,933 |
| **Natural Gas Revenues** | | | | | |
| Residential | **$1,076,323** | $1,150,187 | $1,020,544 | $944,010 | $594,279 |
| Commercial | **327,344** | 349,596 | 287,926 | 266,409 | 192,023 |
| Industrial | **39,971** | 42,588 | 36,147 | 27,312 | 20,883 |
| Other | **140,979** | 130,488 | 100,440 | 86,162 | 83,735 |
| Transportation of customer-owned natural gas | **91,908** | 91,376 | 89,843 | 99,896 | 84,927 |
| **Total Retail** | **1,676,525** | 1,764,235 | 1,534,900 | 1,423,789 | 975,847 |
| Wholesale | **563** | 643 | 182 | 21,070 | 17,260 |
| Other | **20,513** | 18,669 | 14,068 | 17,268 | 39,432 |
| **Total Natural Gas Revenues** | **$1,697,601** | $1,783,547 | $1,549,150 | $1,462,127 | $1,032,539 |

# DIRECTORS AND OFFICERS

## Board of Directors

**JAMES H. BRANDI**, a director since June 2006, formerly Managing Director and Deputy Global Head of the Energy and Power Group of UBS Securities, LLC, is a member of Hill Street Capital LLC in New York, New York.

**JOHN T. CARDIS**, a director since 2005, formerly a partner of Deloitte & Touche USA, LLP, New York, New York, is a director of Edwards Lifesciences Corporation in Irvine, California and Avery Dennison Corporation in Pasadena, California.

**JOSEPH J. CASTIGLIA**, a director since 1995 and currently lead director, is Chairman of the Board of Trustees of MTB Group of Funds in Pittsburgh, Pennsylvania.

**LOIS B. DEFLEUR**, a director since 1995, is President of Binghamton University in Binghamton, New York.

**G. JEAN HOWARD**, a director since 2002, is Chief of Staff, Office of the Mayor, City of Rochester in Rochester, New York.

**DAVID M. JAGGER**, a director since 2000, is President and Treasurer of Jagger Brothers, Inc. in Springvale, Maine.

**SETH A. KAPLAN**, a director since 2005, formerly a partner of Wachtell, Lipton, Rosen & Katz, New York, New York, is a Coadjutant member of the faculty at Rutgers *University School of Law – Newark in Newark, New Jersey.*

**BEN E. LYNCH**, a director since 1987, is President of Winchester Optical Company in Elmira, New York.

**PETER J. MOYNIHAN**, a director since 2000, formerly Senior Vice President and Chief Investment Officer of UNUM Corporation in Portland, Maine.

**WALTER G. RICH**, a director since 1997, is Chairman, President, Chief Executive Officer and a director of Delaware Otsego Corporation in Cooperstown, New York and its subsidiary, The New York, Susquehanna & Western Railway Corporation.

**WESLEY W. VON SCHACK**, a director since 1996, is Chairman, President & Chief Executive Officer of the corporation.

### Committees (Chairperson listed first)

**Audit:** Lynch, Castiglia, Jagger, Kaplan, Moynihan

**Compensation and Management Succession:** Castiglia, Brandi, Cardis, Lynch, Rich

**Corporate Responsibility:** Rich, Brandi, DeFleur, Howard, Moynihan

**Nominating and Corporate Governance:** DeFleur, Cardis, Howard, Jagger, Kaplan

## Energy East Officers

**STEVEN R. ADAMS**, Vice President – Regulatory Policy

**RICHARD R. BENSON**, Senior Vice President and Chief Administrative Officer

**CURTIS I. CALL**, Controller

**PAUL K. CONNOLLY, JR.**, Vice President – General Counsel

**ELAINE T. DUBRAVA**, Secretary

**ROBERT D. KUMP**, Senior Vice President and Chief Financial Officer

**F. MICHAEL MCCLAIN**, Senior Vice President and Chief Development and Integration Officer

***PATRICK T. NEVILLE**, Vice President* – Information Technology

**CLIFTON B. OLSON**, Vice President – Supply

**JESSICA S. RAINES**, Vice President – Procurement and Contracts

**ROBERT E. RUDE**, Senior Vice President and Chief Regulatory Officer

**ANGELA M. SPARKS-BEDDOE**, Vice President – Public Affairs

# SHAREHOLDER SERVICES

Mellon Investor Services LLC (Mellon) is transfer agent, registrar, recordkeeper, disbursing agent and administrator of the Investor Services Program for all Energy East common stock.

EAS

EAS is the trading symbol for Energy East Corporation common stock listed on the New York Stock Exchange.

## Mellon Internet Address: www.melloninvestor.com

Mellon's Internet Website provides shareholders access to Investor Service Direct (ISD). Through ISD, shareholders can view their account profiles, stock certificate and book-entry histories, dividend reinvestment transactions, current stock price quote and historical stock closing prices. Shareholders may request a replacement dividend check, the issuance of stock certificates or the sale of shares from their Investor Services Program account. Shareholders may also utilize a live chat feature with a Mellon customer service representative during regular business hours as reflected below.

Shareholders may also contact Mellon by telephone at 1-800-542-7480. Mellon's automated telephone service is available 24 hours a day, seven days a week. Mellon's customer service representatives are available on regular business days between 9:00 a.m. and 7:00 p.m. (Eastern Time).

**Shareholders may obtain a free copy of our Form 10-K, which is filed each year with the Securities and Exchange Commission, by contacting Investor Relations.**

## Investor Relations

Members of the financial community may contact our Director – Investor Relations by telephone at 207-688-4336.

## Annual Meeting

Formal notice of the meeting, a proxy statement and form of proxy will be mailed to shareholders.

## Trading Symbol: EAS

EAS is the trading symbol for Energy East Corporation common stock listed on the New York Stock Exchange.

## Energy East Internet Address: www.energyeast.com

Information of interest to shareholders, including financial documents and news releases, is available at our Website.

# FACTS AT-A-GLANCE

**Energy East Corporation**

www.energyeast.com

**2,921,000** customers

**$5,231** million revenue

**$11,562** million assets

| **Connecticut Natural Gas Corporation** (CNG) | **The Southern Connecticut Gas Company** (SCG) | **The Berkshire Gas Company** (Berkshire Gas) | **Maine Natural Gas Corporation** (MNG) |
|---|---|---|---|
| www.cngcorp.com | www.soconngas.com | www.berkshiregas.com | www.mainenaturalgas.com |
| 77 Hartland Street, East Hartford, CT 06108 | | 115 Cheshire Road<br>Pittsfield, MA 01201 | P.O. Box 99<br>Brunswick, ME 04011 |
| NATURAL GAS | NATURAL GAS | NATURAL GAS | NATURAL GAS |
| **155,000** customers | **176,000** customers | **36,000** customers | **1,600** customers |
| **31,920** delivered (000 Dth) | **27,079** delivered (000 Dth) | **6,854** delivered (000 Dth) | **23,235** delivered (000 Dth) |
| **$401** million revenue | **$396** million revenue | **$76** million revenue | **$7** million revenue |
| **$922** million assets | **$1,015** million assets | **$230** million assets | **$25** million assets |

**CNG AND SCG OFFICERS**

ROBERT M. ALLESSIO, President and CEO

JAMES E. EARLEY, VP, Controller & Treasurer

JANET L. JANCZEWSKI, Secretary

TIM O. KELLEY, VP Energy Services

WILLIAM REIS, VP Administrative Services

**BERKSHIRE GAS OFFICERS**

ROBERT M ALLESSIO, Chairman and CEO

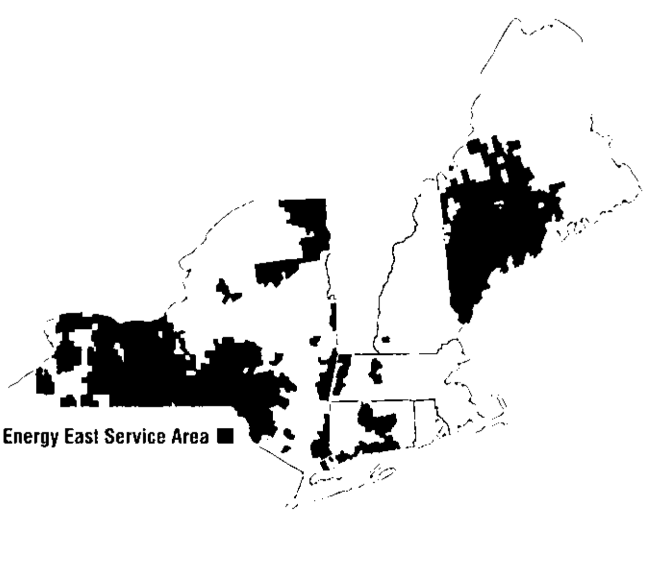
KAREN L. ZINK, President, Treasurer & COO

CHERYL M. CLARK, Clerk

**MNG OFFICERS**

ROBERT M. ALLESSIO, President

DARRELL R. QUIMBY, VP and Clerk



### New York State Electric & Gas Corporation (NYSEG)

www.nyseg.com

### Rochester Gas and Electric Corporation (RG&E)

www.rge.com

89 East Avenue, Rochester, NY 14649

**NYSEG**

**ELECTRICITY**

**871,000** customers

**18,709** delivered (GWh)

**$1,703** million revenue

**NATURAL GAS**

**256,000** customers

**53,012** delivered (000 Dth)

**$440** million revenue

**$3,977** million assets

**RG&E**

**ELECTRICITY**

**359,000** customers

**11,062** delivered (GWh)

**$731** million revenue

**NATURAL GAS**

**296,000** customers

**46,172** delivered (000 Dth)

**$385** million revenue

**$2,480** million assets

**NYSEG AND RG&E OFFICERS**

JAMES P. LAURITO, President and CEO

JEFFREY R. CLARK, Secretary

LAURA CONKLIN, VP Technical Services

MICHAEL H. CONROY, VP Operations

MICHAEL D. EASTMAN, VP Gas Assets

DAVID J. IRISH, VP Fossil / Hydro Operations

DAVID J. KIMIECIK, VP Energy Supply

JAMES A. LAHTINEN, VP Rates and Regulatory Economics

JOSEPH J. SYTA, VP Controller and Treasurer

TERESA M. TURNER, VP Customer Service

### Central Maine Power Company (CMP)

www.cmpco.com

83 Edison Drive
Augusta, ME 04336

**ELECTRICITY**

**596,000** customers

**10,679** delivered (GWh)

**$593** million revenue

**$1,927** million assets

**CMP OFFICERS**

SARA J. BURNS,
President and CEO

KATHLEEN A. CASE,
VP Customer Service

DOUGLAS A. HERLING,
VP Operations

STEPHEN G. ROBINSON,
VP Technical Services

ERIC N. STINNEFORD,
VP Treasurer, Controller & Clerk

### The Energy Network, Inc. (TEN)

81 State Street
Binghamton, NY 13901

**ELECTRICITY**

**132,000** customers

**4,516** delivered (GWh)

**$316** million revenue

**NATURAL GAS**

**42,000** customers

**7,309** delivered (000 Dth)

**$81** million revenue

**$117** million assets

**TEN OFFICERS**

CARL A. TAYLOR,
President and CEO

MARK R. BEAUDOIN,
VP and COO

TERESA BRADFORD,
VP and Controller

JAMES T. DISTEFANO,
VP Sales and Marketing

EnergyEast

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*energyeast.com*

END