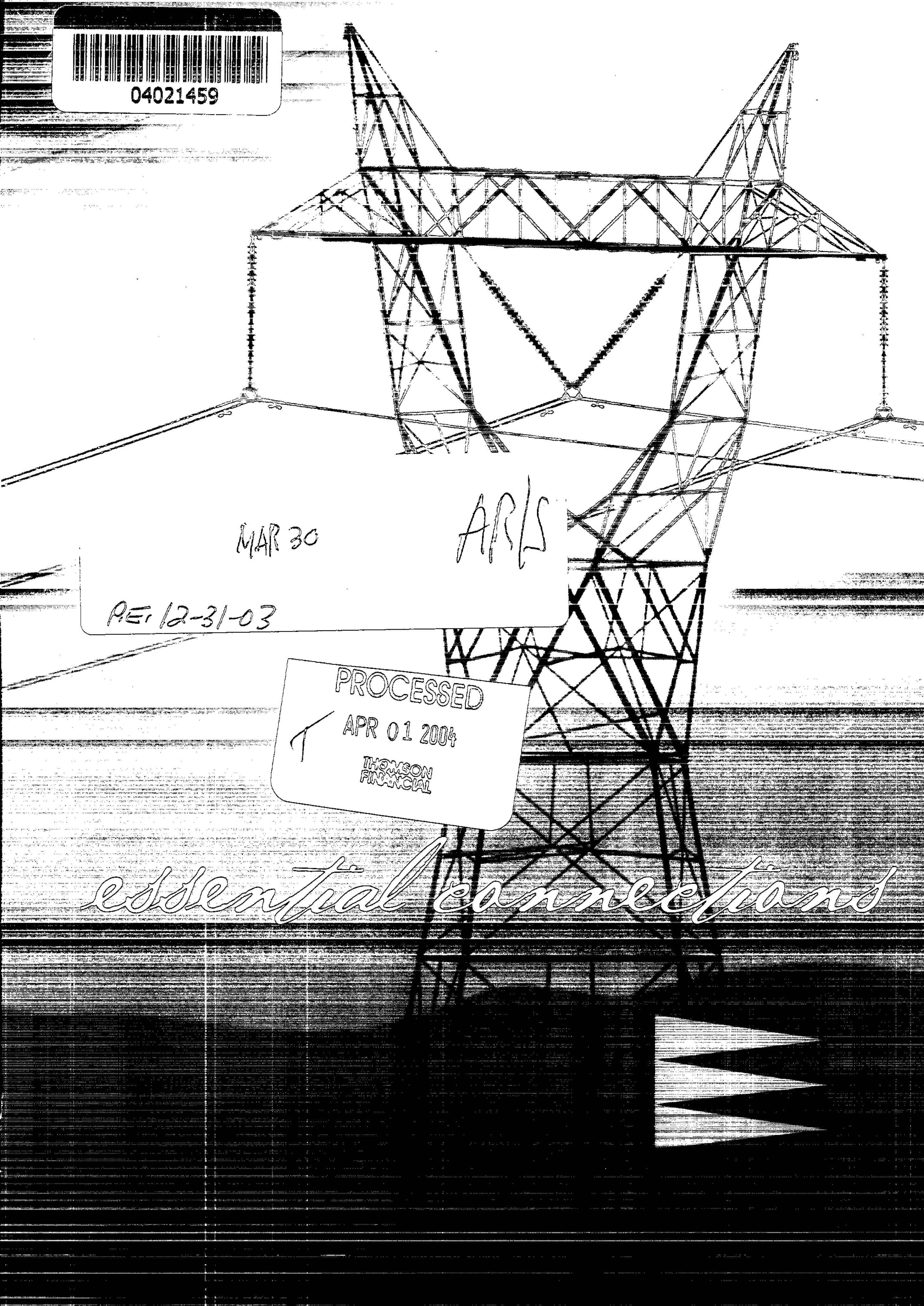
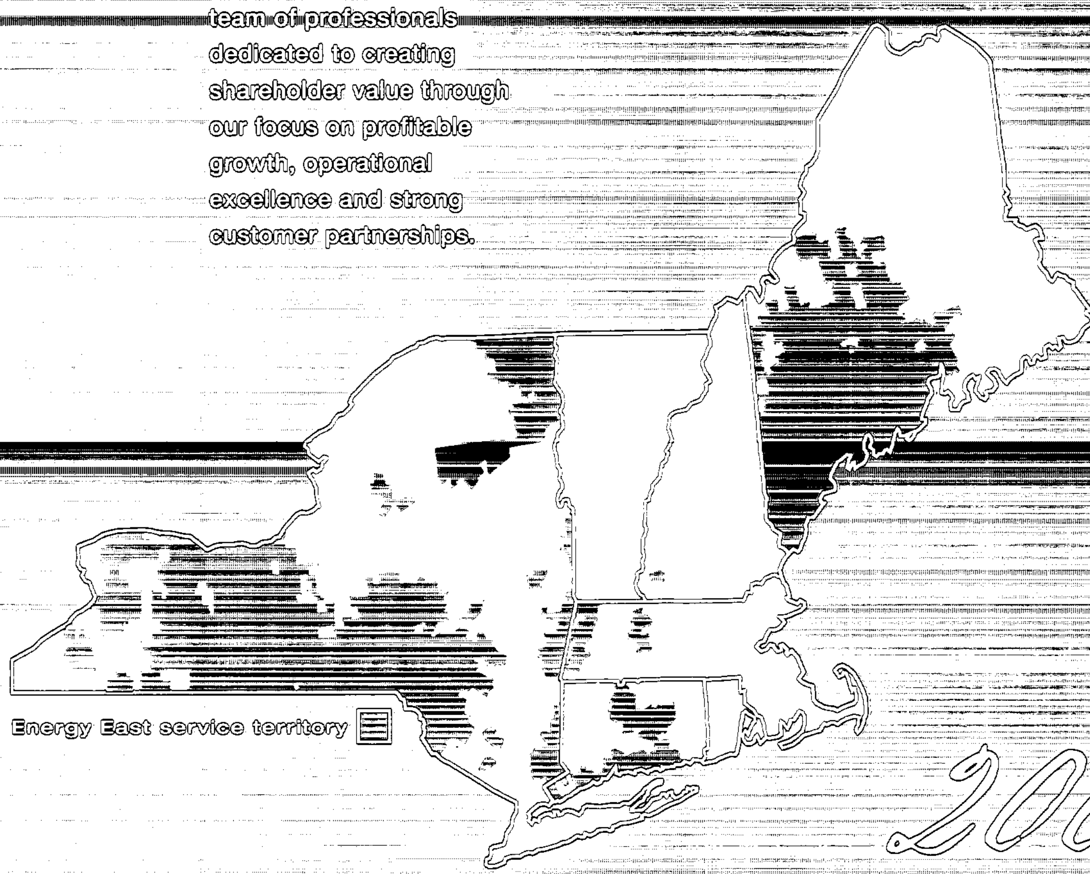


essential connections

ENERGY EAST CORPORATION ANNUAL REPORT 2003

vision Energy East is a respected super regional energy services and delivery company in the Northeast that our customers can depend upon every day. 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.



2003

"Everyday, we are mindful that . . . our customers look to us for a safe, secure and reliable electric and natural gas system."

highlights

January □ Company raises annual dividend 4 cents to $1.00 per share. □ First phase of Supply Chain integration completed. **March** □ Seneca Lake Storage receives approval from FERC for a high-deliverability natural gas storage facility in depleted salt caverns in Reading, NY. **April** □ Major ice storm interrupts power to over two-thirds of RG&E's electric customers. Most have their power restored within three days. □ Company declares 25-cent quarterly common stock dividend. **May** □ Utility Shared Services' consolidated Information Technology operations center opens in Rochester, NY on time and budget. **June** □ CMP announces its fourth rate reduction under its Alternative Rate Plan bringing residential and small business rates down more than 25 percent since 2000. □ Staffing completed for Utility Shared Services' consolidated Supply Chain operations in Rochester, NY. **July** □ Company declares 25-cent quarterly common stock dividend. □ NYSEG's Peg Engasser wins the gold medal for Women's Timber Endurance at the ESPN Great Outdoor Games. □ Second phase of Supply Chain integration completed. **August** □ Major blackout hits the northeast. Most of our electric customers who had their power interrupted are back on line that night. **September** □ Utility Shared Services' facility for consolidated Accounting and Finance departments opens in New Gloucester, ME. □ RG&E files an application with New York State for a $75 million transmission project to improve and expand its electric transmission system in the Greater Rochester area. □ CMP sends line crews to Maryland to assist with restoration effort from Hurricane Isabel. **October** □ Company sells Griffith Oil. □ Company declares 25-cent quarterly common stock dividend. □ NYSEG line team finishes in the top 20 in the International Lineman's Rodeo competition for investor-owned utilities. **November** □ Company sells Berkshire Propane. □ Energy East Corporation redeems approximately $145 million of outstanding debt primarily with cash from the sale of non-utility businesses. □ RG&E announces agreement to sell the Ginna Nuclear Plant for $422.6 million. **December** □ CNG completes a 10-year project to eliminate virtually all of its bare steel gas main in Greenwich, CT. □ Company concludes year with all utilities achieving customer service targets established by regulators.

March 8, 2004

Dear Shareholders:

2003 was a year of excellent progress for Energy East, and in January this year we increased our common stock dividend 4%. This is the seventh consecutive year of dividend growth. We believe that Energy East's common stock, especially with the recent federal income tax reduction on dividends, is a valuable component of any investor's portfolio. Your investment in Energy East returned 6% in 2003 and has returned 28% over the past three years.

Energy East's track-record is largely attributable to our focused, "pipes and wires" strategy and our unwavering commitment to achieving operational excellence across our organization. We understand that even the best companies can get better. And so, over the past year, we have concentrated on identifying ways that we can operate more efficiently and effectively through the integration of our six electric and natural gas utilities.

In 2003 the operating utilities created a "utility shared services" organization, which is responsible for information systems, purchasing, accounting, and finance for all the utilities. Streamlining and centralizing these functions results in substantial savings.

This year we will undertake a new Work Management System, which will allow us to better plan construction, service and preventative maintenance work. The Work Management System is scheduled to go into operation in early 2005 and will be the foundation for many years of operational excellence. These and other actions we are taking are expected to result in savings of approximately $100 million annually by 2006 – $20 million above our original estimate.

Everyday, we are mindful that while our industry continues to be restructured by state and federal regulators, at the end of the day, our customers look to us for a safe, secure and reliable electric and natural gas system. Superior customer service is a top priority at each of our utilities. In 2003, all of our utilities continued to meet their regulatory targets for customer satisfaction and reliability.

"Superior customer service is a top priority at each of our utilities."

Of course, industry restructuring and uncertain regulatory policies do, at times, make it extremely difficult to operate the business, but we must do the best we can to stay focused on the safe and reliable delivery of electricity and natural gas. It is not only essential to our nation's security, but its economy as well. The August blackout was a wake-up call for public policy makers and utilities as to the restructuring hurdles that remain. Fortunately, Energy East's system was not significantly affected and most of our electric customers who had their power interrupted were back on line that same night.

Still, we recognize that of the issues facing the electric industry, enhanced system reliability is one of the most critical. At Energy East, we have continued to invest in the infrastructure that supports our ability to deliver electricity and natural gas to our customers. During 2003 we announced a $75 million transmission project in the city of Rochester, which would enhance system reliability and allow for future growth. Infrastructure investments of this type are needed throughout the United States, but they will only be made if regulators allow utilities to earn a fair return on their investments. In short, as an investor owned company, we have a responsibility to spend our shareholders' money prudently.

One of our utilities, RG&E, exemplifies the struggle many regulated companies encounter when trying to balance customers' needs and regulatory policies with a fair return to shareholders. For the past two years, RG&E has been unable to reach agreement with the Staff of the New York Public Service Commission (PSC) on any kind of rate plan. The Staff wants to continue to reduce RG&E's electric rates – already down 21% over the last ten years on an inflation-adjusted basis –

yet also demands higher levels of reliability and service. Unfortunately, RG&E can no longer continue to do both. As I write this letter, RG&E continues to work toward achieving a satisfactory rate plan that will reflect the interests of both customers and shareholders.

While we strive to find constructive solutions to the regulatory challenges facing our company, please be assured that we at Energy East will also remain focused on doing what we do best – energy transmission and distribution. Currently, less than 5% of our earnings is generated from non-utility businesses that were inherited with our acquisitions. This past year we sold Berkshire Propane, Griffith Oil and reached agreement for the sale of RG&E's Ginna Nuclear Power Plant. The proposed Ginna sale is subject to satisfactory and appropriate approvals from the Nuclear Regulatory Commission, the Securities and Exchange Commission, the Federal Energy Regulatory Commission and the New York PSC.

With those divestitures, 96% of Energy East's $11 billion in assets is now dedicated to regulated businesses. In addition, the proposed sale of Ginna will bring Energy East much closer to being a pure energy distribution company. Once the sale is complete, we will have only about 600 megawatts of generation, including several natural gas turbine plants, attractive renewable hydro plants, and one 1950's vintage coal generation plant, which we plan to decommission in 2007.

"I am pleased to report to you that in an independent survey last year Energy East was rated in the top quartile of S&P 400 companies for excellence in corporate governance."

I am pleased to report to you that in an independent survey last year Energy East was rated in the top quartile of S&P 400 companies for excellence in corporate governance. Your Board of Directors has long considered good corporate governance practices an important contributor to Energy East's long-term success, and recently adopted some new policies to further strengthen our accountability to you, including:

> Shareholder approval for the adoption of a shareholder rights plan, or "poison pill";

> Shareholder ratification of Energy East's independent public accountant;

> The implementation of stock ownership guidelines for directors and executive officers;

> The elimination of loan provisions for executives in the stock option plan; and

> A proposal to be voted on by shareholders at the June 2004 Annual Meeting to declassify the Board of Directors and have all Directors elected annually.

As we look to 2004, you can expect our initiatives to continue to support our focused energy distribution strategy. We will continue to concentrate on operational excellence through the systematic integration of our utilities. We will continue to strengthen our balance sheet and to look for opportunities that serve the long-term interests of both our customers and shareholders. And most importantly, we will remain committed to providing you, our shareholders, with an investment that provides returns in an ethical and transparent manner.

On behalf of the Board of Directors, we thank you for your support of our Company.

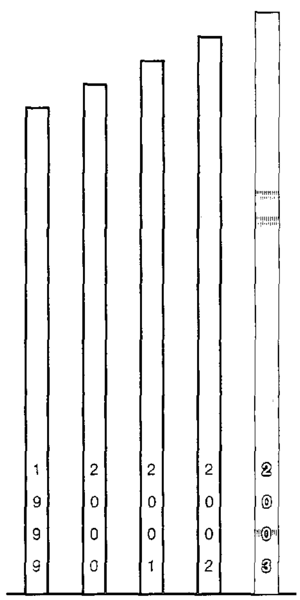
Wes Von Schack

Wesley W. von Schack
Chairman, President & Chief Executive Officer

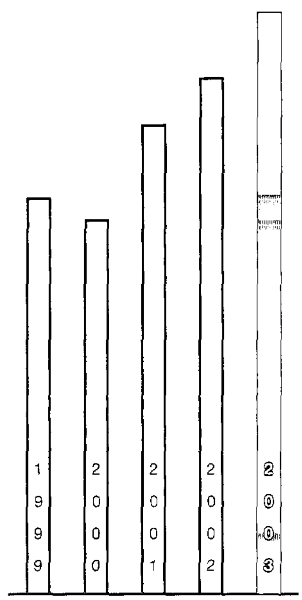
Per Common Share	2003	2002	% Change
Earnings, basic	$1.45	$1.44	1
Earnings, diluted	$1.44	$1.44	–
Dividends Paid	$1.00	$.96	4
Book Value at Year End	$17.59	$16.97	4
Price at Year End	$22.40	$22.09	1
Other Common Stock Information (Thousands)			
Average Common Shares Outstanding, basic	145,535	131,117	11
Average Common Shares Outstanding, diluted	145,730	131,117	11
Common Shares Outstanding at Year End	146,262	144,966	1
Operating Results (Thousands)			
Total Operating Revenues	$4,593,819	$3,836,469	20
Total Operating Expenses	$3,943,705	$3,243,674	22
Net Income	$210,446	$188,603	12
Energy Distribution:			
Megawatt-hours –			
Retail Deliveries	30,593	26,869	14
Wholesale Deliveries	5,734	5,330	8
Dekatherms –			
Retail Deliveries	212,745	181,859	17
Wholesale Deliveries	5,360	7,074	(24)
Total Assets at Year End (Thousands)	$11,306,432	$10,944,347	3

financial

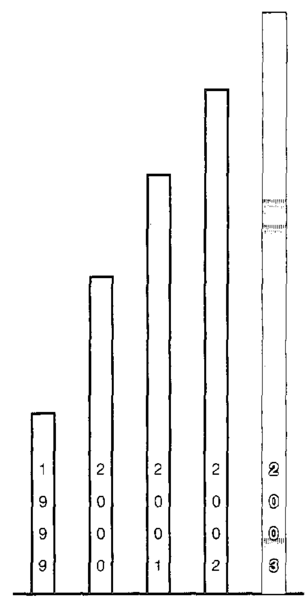
"We believe that Energy East's common stock, especially with the recent federal income tax reduction on dividends, is a valuable component of any investor's portfolio."



Dividend Growth



Electric Deliveries
Megawatt-hours



Natural Gas Deliveries
Dekatherms

highlights

5 CONNECTIONS

Overview

Energy East Corporation's (Energy East or the company) management focuses its strategic efforts on those areas of the company that it believes would have the greatest effect on shareholder value. Efficient operations are a key aspect of increasing shareholder value. As discussed below, management has implemented plans to achieve savings through a company-wide restructuring, consolidation of utility support services and other changes.

In addition, because Energy East's primary operations – its electric and natural gas utility operations – are subject to rate regulation, the approved regulatory treatment on various matters could significantly affect the company's operations and, therefore, its financial position and results of operations. Energy East has long-term rate plans for New York State Electric & Gas Corporation (NYSEG), Central Maine Power Company (CMP), Connecticut Natural Gas Corporation (CNG), The Southern Connecticut Gas Company (SCG) and The Berkshire Gas Company (Berkshire Gas). The plans provide for sharing of achieved savings among customers and shareholders, allow for recovery of certain costs including exogenous and stranded costs, and provide stable rates for customers and revenue predictability for those five operating companies. As discussed below, the company is currently seeking approval of new rates for Rochester Gas & Electric Corporation (RG&E).

Over the last several years Energy East has changed its strategic focus to its electric and natural gas delivery operations, rather than on the more volatile electricity generation business, and has sought to rationalize its nonutility businesses to ensure they fit its strategic focus. As discussed below, during 2003 the company reached an agreement to sell its Ginna nuclear generating station (Ginna) and completed the sale of two of its nonutility businesses.

The continuing evolution of the utility industry, particularly the electric utility industry, has resulted in several federal and state regulatory proceedings that could significantly affect operations, although the outcomes of those proceedings are difficult to predict. These proceedings could have an effect on the nature of the electric and natural gas utility industry in New York and New England and are described below.

The company engages in various investing and financing activities to meet its strategic objectives. Investing activities are primarily for maintaining a reliable energy delivery infrastructure and are funded primarily with internally generated funds. Financing activities, therefore, are focused on maintaining adequate liquidity, improving credit quality and minimizing the cost of capital.

Liquidity and Capital Resources

Restructuring

In 2002 Energy East initiated a corporate restructuring designed to achieve optimum organizational efficiency and effectiveness. The savings from this initiative are essential for the company to meet the rate reduction or efficiency targets imputed in utility rates by regulators, as well as to meet the expectations of customers and investors. In the fourth quarter of 2002 Energy East recorded $41 million of restructuring expenses related to its voluntary early retirement and involuntary severance programs at six of its operating companies. The restructuring expenses would have been $36 million higher, however, RG&E was required by a New York State Public Service Commission (NYPSC) order approving RGS Energy Group, Inc.'s (RGS Energy) merger with the company to defer its portion of the restructuring charge for future recovery in rates. During 2003 the entire related involuntary severance liability of $9 million was paid, including $4 million that was deferred for recovery by RG&E.

The voluntary early retirement program resulted in a reduction of 486 employees in the first quarter of 2003. Collectively the voluntary early retirement and involuntary severance programs resulted in a reduction in overall employee headcount of 678, or 8%, in 2003, including 79 from CMP, 255 from NYSEG and 253 from RG&E.

Integration savings are expected to be approximately $100 million annually by 2006. Those savings, which include reductions in operating expenses and capital expenditures, will come from the consolidation of functions such as accounting, finance, information services and purchasing, as well as the implementation of other merger-enabled initiatives across the six operating utilities. The company completed its consolidation of information systems and purchasing functions during the second quarter of 2003. On September 30, 2003, Energy East received authorization from the Securities and Exchange Commission (SEC) to form a shared services company that provides services, including accounting, treasury, information services, payroll and purchasing functions, to six operating companies.

The company has consolidated the accounting and finance functions of five of its operating companies to one location and has reorganized and relocated the accounting and finance functions of its management subsidiary. In connection with this restructuring, in the fourth quarter of 2003 Energy East recognized $2 million of an estimated liability of $4 million for an enhanced severance program for certain accounting and finance employees who will be employed through March 31, 2004.

Electric Delivery Business

The company's electric delivery business consists primarily of its regulated electricity generation, transmission and distribution operations in upstate New York and Maine.

[illegible] > In February 2002 RG&E filed a request with the NYPSC for new electric and natural gas rates to go into effect on January 15, 2003. The single year filing, as updated, supported an increase in annual electric rates of $40 million, or 5.7%, and an increase in natural gas rates of $19 million, or 6.6%. In December 2002 the administrative law judge (ALJ) in this proceeding issued a recommended decision that, if approved, would have resulted in a $9 million, or 3.3%, overall increase for natural gas service and no increase for electric service.

On March 7, 2003, the NYPSC issued an order (Order) in the proceeding authorizing a $16 million electric revenue requirement reduction. The order requires a $16 million increase in the amortization of previously deferred costs. The NYPSC also limited the natural gas rate increase to $6 million, or 1.9%. The rate decision set the cost of equity at 9.96%, based on an equity ratio of 41.4% and an overall weighted cost of capital of 8.11%. The NYPSC also credited to customers $55 million of electric earnings that, according to the NYPSC, exceeded a preset level under the five-year rate plan that expired on June 30, 2002, subject to a final audit of the fifth year amount. The NYPSC also ignored the costs of replacement power that were incurred during the required Ginna refueling outage in the fall of 2003.

RG&E was disappointed with the Order because it ignored the record that was developed in the proceeding, reversed many of the recommendations of the ALJ without adequate explanation and did not provide adequate revenue for RG&E to earn its authorized rate of return. In May 2003 RG&E began a proceeding to appeal the most objectionable errors in the Order. That proceeding is now before the Appellate Division, Third Department, of the New York State Supreme Court. A decision on the proceeding is expected in 2004.

[illegible] > On April 9, 2003, RG&E filed a letter with the NYPSC requesting the deferral of costs, including interest, for restoration work resulting from a severe ice storm in April 2003 and replacement purchased power costs incurred in 2003 in connection with a scheduled refueling outage for Ginna. The deferred costs are $35 million for repairs required due to the ice storm and $15 million for the Ginna replacement purchased power. These costs are included in RG&E's 2003 Electric and Gas Rate Proceeding described below.

On April 29, 2003, RG&E received a response from the NYPSC that described the NYPSC's history of allowing net prudent costs of this nature, which have a material effect on earnings, to be deferred and recovered from customers. The letter acknowledged that the ice storm and the Ginna replacement purchased power costs are not currently included in RG&E's rates. In its litigation case filed on December 31, 2003 (see RG&E 2003 Electric and Gas Rate Proceeding), the Staff of the NYPSC recommends against recovery of the Ginna replacement purchased power costs as part of the rate case because it has not completed its review. Nevertheless, based on the NYPSC letter, RG&E believes that recovery is probable and has deferred those costs pending approval from the NYPSC, which is expected in 2004.

On May 15, 2003, RG&E filed a letter with the NYPSC seeking deferral and true up of an estimated $9 million of pension costs in accordance with the NYPSC's Statement of Policy Concerning the Accounting and Ratemaking

Treatment for Pensions and Post Retirement Benefits Other than Pensions. The request covers the 16-month period from January 1, 2003, through May 1, 2004, the expected effective date of rates in RG&E's 2003 Electric and Gas Rate Proceeding. In its litigation case filed on December 31, 2003, the Staff of the NYPSC recommends against recovery of these pension costs as part of the rate case because it has not completed its review.

RG&E 2003 Electric and Gas Rate Proceeding > On May 16, 2003, RG&E filed a new rate case with the NYPSC to recover costs that RG&E has incurred and will continue to incur in providing safe and reliable electric and natural gas service. The filing proposed an annual increase in electric rates of $105 million, or 16.2%, and an annual increase in natural gas rates of $25 million, or 7.6% overall and 19.7% on delivery rates. In August 2003 RG&E submitted rate revisions requesting a $98 million annual electric rate increase and a $25 million annual natural gas rate increase. In February 2004 RG&E submitted further rate revisions based on continued review of its filing, requesting instead an $80 million annual electric rate increase and a $21 million annual natural gas rate increase. RG&E's filing cites inadequate rate relief from the NYPSC's Order issued March 7, 2003, increased costs (see RG&E Cost Deferral Petitions) and the need for a fair and reasonable return on equity (ROE) of 11.25%. In order to allow negotiations for a long-term rate plan, the NYPSC issued four orders in October and November 2003 granting RG&E's requests for extensions of the date for rates to become effective, subject to a make whole provision back to April 29, 2004.

On November 19, 2003, RG&E, Staff of the NYPSC and other parties reached a detailed, comprehensive Agreement in Principle on five-year electric and natural gas rate plans. In the process of converting that Agreement in Principle to a Settlement Agreement, RG&E, Staff and certain intervenors reached an impasse. As a result, settlement discussions ceased on December 12, 2003, and the case was placed on a litigation track.

On December 22, 2003, Chairman Flynn of the NYPSC issued a one-Commissioner order transferring the ratemaking treatment for the sale of Ginna from RG&E's pending Section 70 filing (see Sale of Ginna Station and Relicensing) to the pending electric rate proceeding. RG&E filed a Petition for Rehearing of that one-Commissioner order on January 9, 2004, and two intervenors subsequently filed an opposition to RG&E's Petition for Rehearing.

Staff's litigation case under this proceeding was filed on December 31, 2003, and proposes to hold electric revenues constant through an electric base rate reduction of $7 million, an acceleration of the amortization of the Nine Mile Point 2 nuclear generating station (NMP2) regulatory asset, and the implementation of a $7 million retail access surcharge. Staff is also proposing a natural gas delivery rate reduction of $7 million and the implementation of a $7 million merchant function charge. In January 2004 RG&E filed rebuttal testimony that addressed and took exception to the position taken by the Staff of the NYPSC. The Staff position, if adopted by the NYPSC, would be expected to result in an ROE in 2004 of about 4% for RG&E. Hearings on the electric and natural gas rate requests took place in February 2004. On February 25, 2004, RG&E proposed to further extend the date for rates to become effective and to extend the litigation schedule to provide an opportunity for further settlement negotiations. After the ALJ agreed to the proposal, settlement discussions resumed on March 2, 2004. RG&E expects the NYPSC to issue a rate order in August 2004, unless long-term rate plans are negotiated and approved earlier.

RG&E Electric Rate Unbundling > On June 5, 2003, as required by the NYPSC's Order issued March 7, 2003, RG&E filed documentation with the NYPSC to unbundle commodity charges from delivery charges and to create electric commodity options for all customers. This filing has been incorporated into the ongoing 2003 Electric and Gas Rate Proceeding. In that proceeding RG&E proposes to continue to charge customers bundled rates, with an Electric Supply Reconciliation Mechanism, for the period May 1, 2004, through December 31, 2004. RG&E's unbundling filing proposes separate delivery and commodity service options (modeled on NYSEG's commodity service options) to become effective January 1, 2005, for two periods of two years: 2005 through 2006 and 2007 through 2008.

Sale of Ginna Station and Relicensing > On November 25, 2003, RG&E announced an agreement to sell Ginna to Constellation Generation Group LLC (CGG). On December 18, 2003, RG&E and CGG jointly filed a revised Section 70 petition with the NYPSC that includes, among other things, all the transaction documents, details of the auction process and RG&E's proposed accounting and ratemaking treatment for the sale. RG&E's ratemaking proposal includes an incentive payment for having maximized the proceeds from the sale of Ginna and 50/50 customer/

stockholder sharing of any net gain on the sale of Ginna, to the extent that RG&E's earned ROE exceeds 10.45%, its currently authorized threshold for earnings sharing. RG&E's sale of Ginna is conditioned on receiving all required regulatory approvals, including reasonably satisfactory accounting and ratemaking treatment.

Upon closing of the proposed Ginna sale, RG&E will transfer approximately $202 million of decommissioning funds to CGG, which will take responsibility for all future decommissioning funding. The amount is expected to fully meet the Nuclear Regulatory Commission's (NRC) decommissioning funding requirements for Ginna. It is projected that $59 million in excess decommissioning funds will be retained by RG&E and will be shared with customers as directed by the NYPSC. The sale agreement includes a 10-year purchase power agreement so that RG&E's customers continue to receive the benefit of power from Ginna.

The sale of Ginna is subject to approvals by several regulatory agencies, including the NYPSC, the NRC and the Federal Energy Regulatory Commission (FERC). The outcome of these proceedings cannot be determined at this time.

Ginna's operating license expires in 2009. In July 2002 RG&E filed a license renewal application with the NRC, which, if approved, would extend the license to September 19, 2029. The NRC has deemed the application complete. The NRC held two sets of public meetings in 2002 and two in 2003. A decision on this matter is expected in the second quarter of 2004.

In October 2003 RG&E completed the 31st refueling of the reactor core at Ginna, which will support operations through the spring of 2005. During this refueling outage RG&E also successfully replaced Ginna's reactor vessel head as previously scheduled, without significantly extending the duration of the refueling outage as compared to previous outages. Several nuclear power plant operators had identified defects in their reactor vessel heads, which prompted heightened NRC oversight. RG&E thoroughly reviewed the issue and implemented an inspection plan during Ginna's spring 2002 refueling outage. Although the inspection demonstrated that Ginna could continue to operate with the existing reactor vessel head, RG&E decided to replace the reactor vessel head in order to avoid significant expenditures associated with maintenance, inspections and the length of future outages. The cost of the replacement was $14 million and is expected to be recovered in rates.

RG&E Transmission Project > On September 30, 2003, RG&E applied to the NYPSC for approval to upgrade its electric transmission system. The project includes building and rebuilding 38 miles of transmission lines and upgrading substations in the Rochester, NY, area in order to assure adequate service to customers after the anticipated closing of RG&E's 257 megawatt coal-fired Russell Station in 2007. The estimated cost of the multi-year project is $75 million, which is expected to be recovered in rates, and actual construction on the project is expected to begin in the spring of 2005.

CMP Alternative Rate Plan > In September 2000 the Maine Public Utilities Commission (MPUC) approved CMP's Alternative Rate Plan (ARP 2000). ARP 2000 applies only to CMP's state jurisdictional distribution revenue requirement and excludes revenue requirements related to stranded costs and transmission services. ARP 2000 began January 1, 2001, and continues through December 31, 2007, with price changes, if any, occurring on July 1, in the years 2002 through 2007. In March 2003 CMP submitted its annual ARP filing proposing a decrease of 7.82% on the distribution portion of rates, which reflects a decrease in ice storm amortization expense and other items. In June 2003 the MPUC approved the decrease, which became effective July 1, 2003.

CMP Electricity Supply Responsibility > Under a Maine State Law adopted in 1997, CMP was mandated to sell its generation assets and relinquish its supply responsibility. CMP no longer owns any generating assets but does retain its power entitlements under long-term contracts from nonutility generators (NUGs) and a power purchase contract with Vermont Yankee and its ownership interests in three nuclear facilities that have been shut down. CMP has sold the entitlements for a three-year period ending February 28, 2005. CMP's retail electricity prices are set to provide recovery of the costs associated with these ongoing obligations.

Under Maine State Law the MPUC can mandate that CMP be a standard-offer provider for supply service if the MPUC should deem bids by competitive suppliers to be unacceptable. CMP has no standard-offer obligations through August 2004. In January 2004 the MPUC chose a combination of three suppliers of standard-offer electricity for the six months beginning March 1, 2004, for the medium and large customer classes. If in the future CMP should have standard-offer obligations, there would be no effect on net income because CMP is ensured cost recovery through Maine State Law for any standard-offer obligation. CMP's revenues and purchased power costs would fluctuate, however, if its status as a standard-offer provider changes. (See Operating Results for the Electric Delivery Business and Note 10 to the Consolidated Financial Statements.)

[illegible] In December 2002 the MPUC initiated an investigation to review CMP's current level of recovery of stranded costs, including the costs associated with decommissioning the Yankee Atomic plant. In June 2003 the MPUC approved a stipulation agreeing to a total reduction of $7 million in stranded cost rates over the period July 2003 through February 2005. The reduction reflects lower anticipated Maine Yankee costs and higher sales levels. The stipulation also provides for deferral and recovery of Yankee Atomic decommissioning costs not currently included in rates.

In response to a request from the Industrial Energy Consumers Group to mitigate high supply prices, the MPUC ordered CMP to lower stranded cost prices for medium and large commercial and industrial customers by $.003 per kilowatt-hour for the period July 2003 through February 2005. The mitigation is being funded from CMP's asset sale gain account.

[illegible] In February 2002 the NYPSC issued an Order (NYPSC February 2002 Order) approving a five-year NYSEG electric rate plan, which extends through December 31, 2006, and Energy East's merger with RGS Energy. NYSEG's and the company's earnings were lower in 2002 (one year earlier than expected) as a result of the electric rate plan because NYSEG's electric rates were adjusted to reflect the sale of generation assets that was completed in 1999.

The NYPSC February 2002 Order reduced annualized electric rates by $205 million for NYSEG customers effective March 1, 2002, which amounted to an overall average reduction of 13% for most customers. In the first rate year ending December 31, 2002, approximately $55 million of the annualized reduction was funded with the partial amortization of an asset sale gain account created as a result of NYSEG's sale in 2001 of its interest in NMP2. The NYPSC February 2002 Order also requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 15.5% for 2002, and equal sharing on the greater of ROEs in excess of 12.5% on electric delivery, or 15.5% on the total electric business (including supply) for each of the years 2003 through 2006. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $700 million.

[illegible] In December 1999 NYSEG notified the owners of Allegheny Hydro No. 8 and Allegheny Hydro No. 9 demanding that they each provide adequate assurance that they will perform their individual contractual obligations under two power purchase agreements with NYSEG, including the obligation to pay back overpayments made by NYSEG over the course of the agreements. Such overpayments are the cumulative difference between the rate NYSEG pays for power under the agreements and its actual avoided costs. At the end of 2003 this cumulative overpayment was more than $194 million and is expected to grow substantially by 2030 when both agreements expire. Allegheny and its lenders filed a motion in the New York State Supreme Court (N.Y. County) seeking a declaration that NYSEG's demand for adequate assurance was improper. The parties reached a settlement in January 2004. The settlement included a dismissal of all of NYSEG's claims and all of Allegheny's claims and a payment to NYSEG to secure continued operation of the plants.

CMP and NYSEG together expensed approximately $608 million for NUG power in 2003. They estimate that their combined NUG power purchases will total $642 million in 2004, $683 million in 2005, $609 million in 2006, $574 million in 2007 and $367 million in 2008. 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 2003, averaged 9.5 cents per kilowatt-hour for CMP and 8.7 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's and NYSEG's current regulatory plans. (See Note 10 to the Consolidated Financial Statements.)

[illegible] In March 2000 the NYPSC instituted a proceeding to address the future of competitive electricity and natural gas markets, including the role of regulated utilities in those markets. Other objectives of the proceeding include identifying and suggesting actions to eliminate obstacles to the development of those competitive markets and providing recommendations concerning Provider of Last Resort and related issues. A recommended decision (RD) addressing these matters is before the NYPSC.

In a separate phase of this proceeding, the NYPSC issued an order in November 2001 directing the development of embedded cost of service studies for use in implementing unbundled rates. A separate RD on the embedded cost of service studies filed by NYSEG and Consolidated Edison was issued on March 24, 2003. That RD discusses the utilities' cost studies and concludes that they generally comply with the NYPSC's directives. The RD recommended the adoption of NYSEG's lost revenue recovery mechanisms contained in NYSEG's electric and natural gas joint proposals. In April 2003 NYSEG and RG&E filed briefs on the recommended decision. NYSEG took exception to the RD's treatment of certain costs. RG&E filed its brief on exception, not taking formal exception to any of the RD's proposals, but commenting that given the material differences among utilities, it would be both impossible and improper to impose the conclusions in this RD on the remaining utilities in this proceeding. The companies are unable to predict the outcome of this proceeding.

In January 2003 ISO New England, Inc. (ISO New England) announced that it would work with New England transmission owners to seek input and the advice of all market participants, regulators and other stakeholders to pursue the creation of a New England-only regional transmission organization (RTO). ISO New England and the New England transmission owners made a joint RTO filing with FERC on October 31, 2003. FERC has not yet ruled on the filing.

In October 2001 FERC commenced a proceeding to consider national standard market design (SMD) issues, and in July 2002 issued a Notice of Proposed Rulemaking (the SMD NOPR). The SMD NOPR proposes rules that would require, among other things, changes in the wholesale power markets, transmission planning, services and charges, market power monitoring and mitigation, and the organization and structure of ISOs. CMP, NYSEG and RG&E filed comments jointly with other transmission owners in November 2002 and in early 2003. On April 28, 2003, the FERC issued a white paper on SMD in which FERC accommodates greater regional flexibility and seeks further comments. The SMD white paper includes a preference for energy markets based on locational marginal pricing (LMP), which represents a significant change for some regions of the country. The New York Independent System Operator (NYISO) and ISO New England already operate markets based on LMP. The companies are unable to predict the SMD's ultimate effect, if any, on their results of operations or financial position.

In June and July 2001 FERC issued orders that address a number of transmission planning and expansion issues that would directly affect CMP, NYSEG and RG&E as transmission owners. The FERC orders discuss giving exclusive responsibility for the transmission planning process to RTOs, rather than to the transmission owners, and also discuss redefining the cost-sharing responsibilities of interconnecting generators for transmission expansion costs. NYSEG, RG&E and other parties are in discussion with the NYISO on the establishment of a formal regional planning process. Additional transmission planning and expansion proposals are included in the SMD NOPR. On July 31, 2003, ISO New England and the New England Power Pool submitted a filing to FERC concerning transmission expansion cost allocation. On December 17, 2003, FERC approved that filing. CMP, among other parties, requested rehearing of the FERC order, arguing that it would require customers who would not benefit from new transmission projects to contribute to those project costs. On July 24, 2003, FERC issued orders regarding generation interconnection terms, conditions and cost allocation that would require modifications to the companies' interconnection processes. The companies are unable to predict the ultimate effect, if any, of these proceedings on their transmission systems or on future capital expenditures.

In January 2003 FERC issued a proposed policy statement on transmission pricing. FERC proposes a 50 basis point ROE adder on facilities for which transmission owners turn control over to an RTO. The NYISO and ISO New England satisfy most of the requirements of an RTO. In addition, FERC proposes that unaffiliated third parties will receive the equivalent of an additional 150 basis point adder applicable to transmission facilities that transmission-owning utilities divest. Finally, FERC proposes a 100 basis point adder for new transmission facilities found appropriate through an RTO planning process. The company filed comments on FERC's policy proposal in the first half of 2003. CMP has joined with the New England investor-owned transmission owners to request a joint baseline ROE and the above incentives as part of the proposal for a New England-only RTO.

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 (MGP) sites. The RG&E action is being litigated and mediated concurrently and the parties are in the final stages of discovery. RG&E and NYSEG are unable to predict the outcome of these actions at this time.

Natural Gas Delivery Business

The company's natural gas delivery business consists of its regulated natural gas transportation, storage and distribution operations in New York, Connecticut, Maine and Massachusetts.

Natural Gas Supply Agreements > Four of Energy East's natural gas companies – NYSEG, SCG, CNG and Berkshire Gas – have a two-year strategic alliance with BP Energy Company, effective April 1, 2002, for the acquisition of natural gas supply and optimization of transportation and storage services. RG&E has a portfolio management agreement with Entergy-Koch Trading, LP that extends through March 31, 2004, to assist RG&E in the cost-effective management of RG&E's firm contractual rights to natural gas supply, transportation and storage services.

In anticipation of the expiration of these agreements, the companies are conducting a request for proposal process to identify a single strategic alliance partner for all of the Energy East natural gas companies. A new strategic alliance is expected to be effective April 1, 2004. The new alliance will provide the companies with greater supply flexibility, enhance the benefits of a larger natural gas portfolio and be based on sharing incremental savings. The companies will still own and control their natural gas assets and will work with the alliance partner to obtain the lowest cost supply while maintaining reliability of service.

RG&E 2002 Electric and Gas Rate Proceeding > See Electric Delivery Business.

RG&E 2003 Electric and Gas Rate Proceeding > See Electric Delivery Business.

NYPSC Collaborative on End State of Energy Competition > See Electric Delivery Business.

NYSEG Natural Gas Rate Plan > NYSEG's natural gas rate plan, which became effective October 1, 2002, freezes overall delivery rates through December 31, 2008, implemented a gas supply charge to collect the actual costs of gas and contains an earnings sharing mechanism. The earnings sharing mechanism requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 11.5% for the 27-month period ended December 31, 2004, and in excess of 12.5% for each of the calendar years from 2005 through 2008. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $240 million.

SCG Request for Recovery of Exogenous Costs > On December 9, 2003, SCG filed an application with the Connecticut Department of Public Utility Control (DPUC) to recover exogenous costs of approximately $21 million under its approved Incentive Rate Plan (IRP). The recovery for exogenous costs is for qualified pension and other postretirement benefits expense, taxes, uncollectible expense and the Customer Hardship Arrearage Forgiveness Program. These costs were the result of events that were unanticipated and beyond SCG's control. SCG's IRP decision from the DPUC allows SCG to petition for relief from substantial and material costs resulting from such exogenous events. The DPUC has established a docket for this proceeding and initial interrogatories have been issued. SCG cannot predict the outcome of this proceeding at this time.

Connecticut Regulatory Proceedings > During 2001 the Connecticut Office of Consumer Counsel (OCC) filed appeals in State Superior Court arguing that the DPUC's order in December 2000 approving an SCG multi-year IRP and its order in May 2001 approving a CNG IRP were unlawful. In March 2001 the OCC filed a Motion to Stay the implementation of the DPUC's order concerning the SCG IRP, but the court denied the motion in June 2001. In August 2001 the court appeals for SCG's and CNG's IRPs were combined.

In October 2001 SCG and CNG reached a settlement with the OCC, also endorsed by Prosecutorial Staff of the DPUC, resolving numerous outstanding regulatory and legal proceedings. The proceedings resolved by the settlement include a review of past SCG affiliate transactions, SCG's Purchased Gas Adjustment Clause (PGA) charges and credits, alleged overearnings at SCG and CNG, and a court appeal of the DPUC-approved IRPs for SCG and CNG.

SCG and CNG received a final decision from the DPUC approving the settlement in February 2002. The settlement provided rate reductions of $1.5 million for SCG and $0.5 million for CNG, effective October 1, 2001. It extends the approved IRPs for an additional year through September 2005 and maintains an earnings sharing mechanism that generally shares any earnings above the authorized ROEs equally between shareholders and customers. The settlement also permits the recovery of SCG deferred gas costs through the PGA and through the customer portion of earnings sharing by the end of the IRP in 2005. Merger-enabled gas costs savings for both companies are also shared equally between customers and shareholders, with the shareholder portion recovered through the PGA.

CNG's Purchased Gas Adjustment Clause > In April 2002 the DPUC initiated a semiannual review of CNG's PGA. The DPUC issued its draft decision in December 2002, disallowing approximately $1 million of natural gas costs that would be returned to customers through the PGA. As a result, at December 31, 2002, CNG recognized a liability of $1 million for those costs. In May 2003 the DPUC issued its final decision in the matter, modifying the draft decision and removing the disallowance. The DPUC also notified CNG concerning transactions reviewed in an August 2003 semiannual review, for which a final decision is due in mid-2004. CNG is retaining its $1 million reserve contingency to cover the period November 1, 2001, through October 31, 2003, pending completion of the DPUC's review. CNG cannot predict the final outcome of this proceeding.

Connecticut Merger-Enabled Gas Supply Savings and Gas Cost Reduction Plan Filings > In 2001 CNG and SCG submitted filings to the DPUC regarding merger-enabled gas supply savings (MEGS) and a gas-cost reduction plan, which covered the initial period April 1, 2001, through September 30, 2001. CNG provided calculations for total MEGS of $1.3 million and SCG provided calculations for total MEGS of $2.2 million. In February 2003, based on their understanding of the components of the MEGS, the DPUC issued a draft decision on CNG's and SCG's filed MEGS and gas-cost reduction plan results, modifying the MEGS amounts to $134,000 for CNG and $9,000 for SCG. CNG and SCG filed comments and additional detail with regard to the draft decision by the DPUC's extended due date in April 2003. Hearings are ongoing and a final decision is expected in mid-2004. CNG and SCG cannot predict the final outcome of these proceedings.

Berkshire Gas Rate Plan > In January 2002 the Massachusetts Department of Telecommunications and Energy (DTE) approved a rate increase of $2.3 million, or 4.5%, on total annual revenues for Berkshire Gas. The new rates became effective February 1, 2002. The DTE's approval included Berkshire Gas' proposal for a 10-year incentive-based rate plan with a midperiod review after five years. After the initial rate increase, rates will be frozen until September 2004, at which time rates will be adjusted annually based on inflation minus a 1% consumer dividend. The DTE also approved Berkshire Gas' proposed rate design based on seasonal rates for residential and small commercial and industrial customers that are the same in the winter and summer. Berkshire Gas implemented a service quality plan consistent with a DTE ruling for service quality standards. In September 2003 the DTE reviewed and approved Berkshire Gas' 2002 calendar year service quality filing.

Other Businesses

The company's other businesses include a nonutility generating company, retail energy marketing companies, telecommunications assets, a district heating and cooling system, a FERC-regulated liquefied natural gas peaking plant and an energy services, utility locating and construction company.

Sale of Other Businesses > The company continues to rationalize its nonutility businesses to ensure they fit its strategic focus. In May 2003 Berkshire Propane, Inc., a subsidiary of Berkshire Energy Resources, sold about one-fourth of its assets and customers for approximately book value. In November 2003 Berkshire Propane, Inc. sold its remaining assets and in October 2003 Energetix sold its Griffith Oil Co., Inc. subsidiary. Energetix is a subsidiary of RGS Energy. The after tax loss on disposal of Berkshire Propane, Inc. was $2 million and the after tax gain on disposal of Griffith Oil Co., Inc. was $3 million. (See Note 2 to the Consolidated Financial Statements.)

Other Matters

Accounting Issues

Statement 150 In May 2003 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. Statement 150 requires that certain financial instruments be classified as liabilities in statements of financial position. Under previous guidance such instruments could be classified as equity. Energy East and RG&E adopted Statement 150 as of July 1, 2003. The adoption of Statement 150 did not have a material effect on Energy East's or RG&E's financial position or results of operations. (See Notes 1 and 7 to the Consolidated Financial Statements.)

FIN 46R In December 2003 the FASB issued its revised FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin (ARB) No. 51 (FIN 46R). FIN 46R 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. The company adopted the provisions of FIN 46R related to special purpose entities as of December 31, 2003. (See Notes 1 and 7 to the Consolidated Financial Statements.)

Contractual Obligations and Commercial Commitments

At December 31, 2003, the company's contractual obligations and commercial commitments are:

(Thousands)	Total	2004	2005	2006	2007	2008	After 2008
Contractual Obligations							
Long-term debt	$4,018,265	$29,713	$58,684	$339,433	$231,433	$92,433	$3,266,569
Capital lease obligations	31,820	2,526	2,379	2,194	2,053	2,120	20,548
Operating leases	67,732	13,173	11,491	9,586	9,181	9,153	15,148
Nonutility generator purchase power obligations	3,696,200	641,809	683,130	609,375	574,014	366,510	821,362
Nuclear plant obligations[1]	481,227	64,223	85,087	78,966	82,136	104,410	66,405
Unconditional purchase obligations	1,519,345	335,958	236,935	189,254	178,194	141,563	437,441
Pension and other postretirement benefits[2]	2,295,708	177,741	184,517	194,066	203,178	215,252	1,320,954
Other long-term obligations	35,850	7,800	7,850	5,700	4,400	3,200	6,900
Total Contractual Obligations	$12,146,147	$1,272,943	$1,270,073	$1,428,574	$1,284,589	$934,641	$5,955,327
Other Commercial Commitments							
Committed lines of credit	$680,000	$455,000	$225,000	–	–	–	–
Uncommitted lines of credit	16,000	16,000	–	–	–	–	–
Total Commercial Commitments	$696,000	$471,000	$225,000	–	–	–	–

(1) See Sale of Ginna Station and Relicensing.

(2) Amounts are through 2013 only.

Energy East has two revolving credit agreements in which it covenants to maintain certain debt ratios. CMP has a revolving credit facility, secured by its accounts receivable, in which it covenants to maintain certain debt and earnings ratios. NYSEG and RG&E have a joint revolving credit agreement in which they each covenant to maintain certain debt and earnings ratios. NYSEG has a letter of credit and reimbursement agreement in which it covenants to maintain certain debt ratios. (See Note 8 to the Consolidated Financial Statements.)

In preparing the financial statements in accordance with generally accepted accounting principles, 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. The company's most critical accounting estimates include the effects of utility regulation on its financial statements, and the estimates and assumptions used to calculate the asset retirement obligation, perform the annual impairment analyses for goodwill and other intangible assets and calculate pension and other postretirement benefits.

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

The company believes its public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electricity and natural gas operations in New York State, Maine, Connecticut and Massachusetts; however, the company 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 the company's public utility subsidiaries can no longer meet the criteria of Statement 71 for all or a separable part of their regulated operations, they may have to record as expense or revenue certain regulatory assets and liabilities.

Approximately 90% of the company's revenues are derived from operations that are accounted for pursuant to Statement 71. The rates the utilities charge their customers are based on cost basis regulation reviewed and approved by those regulatory commissions.

As required by Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, the company recorded a liability for the fair value of its asset retirement obligation on January 1, 2003. The company will adjust the liability to its present value periodically over time, and the capitalized cost will be depreciated over the useful life of the related asset. The determination of the liability includes various assumptions, the primary assumptions being the discount rate and forecasted cash flows. Changes in those assumptions could have a significant effect on the amount of the company's asset retirement obligation. The company's asset retirement obligation is recovered through rates collected from customers, therefore, the depreciation of the capitalized costs and adjustments to the liability are deferred until those amounts are included in rates. (See Note 1 to the Consolidated Financial Statements.)

Substantially all of Energy East's asset retirement obligation is related to Ginna. (See Sale of Ginna Station and Relicensing.)

The company no longer amortizes goodwill and does not amortize intangible assets with indefinite lives (unamortized intangible assets). Both goodwill and unamortized intangible assets are tested at least annually for impairment. Intangible assets with finite lives are amortized and are reviewed for impairment. The impairment testing includes various assumptions, primarily the discount rate and forecasted cash flows. Impairment testing was done over a range of discount rates representing the company's marginal, weighted average cost of capital as well as a range of assumptions for cash flows. Changes in those assumptions outside of the ranges analyzed could have a significant effect on the company's determination of an impairment. (See Note 5 to the Consolidated Financial Statements.)

The company has pension and other postretirement benefit plans covering substantially all of its employees. In accordance with Statement of Financial Accounting Standards No. 87, Employer's Accounting for Pensions, and Statement of Financial Accounting Standards No. 106, Employer's Accounting for Postretirement Benefits Other Than Pensions, 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, expected years of future service under the pension benefit plans and the methodology used to amortize gains or losses. Changes in those assumptions could have a significant effect on the company's noncash pension income or expense or on the company's postretirement benefit costs. As of December 31, 2003, the company decreased the discount rate from 6.5% to 6.25%. (See Note 16 to the Consolidated Financial Statements.)

Investing and Financing Activities

Investing Activities > Capital spending totaled $303 million in 2003, $229 million in 2002 and $223 million in 2001, including capital spending for RGS Energy and nuclear fuel for RG&E beginning July 1, 2002. Capital spending does not include the amount for the company's merger transaction for RGS Energy in 2002. (See Note 4 to the Consolidated Financial Statements.) Capital spending in all three years was financed with internally generated funds and was primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates and merger integration in 2003.

Capital spending is projected to be $345 million in 2004, including nuclear fuel. It is expected to be paid for with internally generated funds and will be primarily for the same purposes described above. (See Note 10 to the Consolidated Financial Statements.)

The company's pension plans generated pretax noncash pension income (net of amounts capitalized) of $40 million in 2003, $70 million in 2002, and $76 million in 2001. The decrease in 2003 was due to significant equity market declines over the past several years and revised actuarial assumptions including the discount rate used to compute the company's pension liability (reduced from 7.0% to 6.50% as of December 31, 2002) and return on assets (reduced from 9% to 8.75% effective January 1, 2003). Pension income for 2004 is estimated at $40 million. The company estimates funding requirements of only $7 million to $12 million in 2004 since, in the aggregate, total plan assets exceed the projected benefit obligation. (See Note 16 to the Consolidated Financial Statements.)

Financing Activities > (See Notes 7 and 8 to the Consolidated Financial Statements.)

The financing activities discussed below include those activities necessary for the company and its subsidiaries to maintain adequate liquidity, improve credit quality and ensure current access to capital markets to finance certain refundings. These include maintenance of credit facilities, minimal common stock issuances and various medium-term and long-term debt arrangements.

The company raised its common stock dividend 4% in January 2004 to a new annual rate of $1.04 per share.

Since August 2001 the company has been issuing new common shares through its Dividend Reinvestment and Stock Purchase Plan, now called the Investor Services Program, rather than purchasing them on the open market. The company expects to issue approximately one million shares per year under this plan. During 2003 the company issued 1,063,640 shares of common stock at an average price of $20.41 per share through this plan. The shares issued included 328,797 treasury shares and 734,843 original issue shares.

In February 2003 the company awarded 229,230 shares of common stock, issued out of its treasury stock, to certain employees through its Restricted Stock Plan, and recorded deferred compensation of $4 million based on the market price of $19.20 per share of common stock on the date of the award. (See Note 14 to the Consolidated Financial Statements.)

In February 2004 the company awarded 240,138 shares of its common stock, to be issued out of its treasury stock, to certain employees through its Restricted Stock Plan and recorded deferred compensation of $6 million based on the market price of $23.89 per share of common stock on the date of the award.

The company and its subsidiaries have committed credit agreements with various expiration dates in 2004 and 2005 and pay fees in lieu of compensating balances in connection with these credit agreements. These agreements provided for maximum borrowings of $680 million at December 31, 2003, and $755 million at

December 31, 2002. Uncommitted credit agreements, which expire in 2004, provide for additional borrowings of $16 million. (See Contractual Obligations and Commercial Commitments.)

The company and its subsidiaries use short-term, unsecured notes and drawings on their credit agreements (see above) to finance certain refundings and for other corporate purposes. There was $308 million of such short-term debt outstanding at December 31, 2003, and $322 million outstanding at December 31, 2002. The weighted-average interest rate on short-term debt was 1.8% at December 31, 2003, and 2.1% at December 31, 2002.

The company 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. The company plans to use the net proceeds from the sale of securities under this shelf registration for general corporate purposes, such as the repurchase or refinancing of securities. The company had $5 million available under a previous shelf registration statement. The company currently has $805 million available under the shelf registration statement filed in June 2003.

In September 2003 Energy East issued $200 million of 6.75% unsecured notes due in September 2033 under the shelf registration statements described above. The notes were issued as part of an exchange of securities for $156 million aggregate principal amount of the company's 7.75% Putable Asset Term Securities (PATS), putable/callable November 15, 2003, from the holders thereof. The remaining cash proceeds were used to finance the cancellation of the related call option with respect to the exchange of the PATS, to finance expenses associated with the offering and for general corporate purposes. Energy East called the remaining $144 million aggregate principal amount of the PATS in mid-November and funded the transaction with proceeds from the sale of certain nonutility businesses and short-term debt.

In August 2003 Energy East entered into a fixed-to-floating interest rate swap on a portion of its 8 1/4% junior subordinated debt securities. The company receives a fixed rate of 8 1/4% and will pay a rate based on the three-month London Interbank Offered Rate (LIBOR) plus 2.00% on a notional amount of $250 million through July 2031.

In August 2003 Energy East terminated a fixed-to-floating interest rate swap on its 5.75% notes due November 2006. The company received $4 million, the value of the swap on the date of termination, that it will amortize over the remaining life of the notes.

In August 2003 CMP issued $36 million of Series E Medium Term Notes at a fixed rate of 5.1%, due August 2013. Through financial instruments issued in March 2003 CMP locked in the 10-year treasury rate component of that financing at a fixed rate of 4.105%, which reduced the effective rate on the notes by 10 basis points. The proceeds from the notes were used to help repay $50 million of medium term notes that matured in August 2003.

In March 2003 NYSEG filed a shelf registration statement with the SEC to sell up to $300 million in an unspecified combination of debt and preferred stock. NYSEG plans to use the net proceeds from the sale of securities under this shelf registration primarily for the retirement or repurchase of certain of its indebtedness or preferred stock, the reduction of short-term debt and other general corporate purposes. NYSEG had $50 million available under a previous shelf registration statement. NYSEG currently has $150 million available under the shelf registration statement filed in March 2003.

In April 2003 NYSEG redeemed, at a premium, $50 million of 7.55% Series first mortgage bonds callable on April 1, 2003, using commercial paper. NYSEG redeemed $100 million of 7.45% Series first mortgage bonds: $23 million was redeemed at par on June 30, 2003, pursuant to a sinking fund provision in NYSEG's mortgage indenture and $77 million was redeemed at a premium on July 15, 2003. NYSEG has redeemed all of its outstanding first mortgage bonds. NYSEG's first mortgage indenture was discharged in the fourth quarter of 2003.

In May 2003 NYSEG issued $200 million of 5 3/4% unsecured notes due in May 2023 under the shelf registration statements described above. The proceeds of this unsecured issuance were used to refund commercial paper that was used in April 2003 to redeem the $50 million of 7.55% Series first mortgage bonds, and to redeem in June and July 2003 the $100 million of 7.45% Series first mortgage bonds. NYSEG used the remainder of the net proceeds for general corporate purposes. NYSEG will amortize, over the term of the 5 3/4% unsecured notes, a $1 million premium on the redemption of its 7.55% Series first mortgage bonds, a $3 million premium on the redemption of its 7.45% Series first mortgage bonds and related unamortized debt expenses and debt issuance costs for both redemptions.

In January 2003 RG&E used an equity contribution from its parent, RGS Energy, along with internally generated funds, to pay off the remaining $80 million balance of a 7% promissory note that was due in 2014.

RG&E paid at maturity in February 2003 $39 million of first mortgage bonds and in March 2003 $1 million of first mortgage bonds using temporary cash investments and internally generated funds. RG&E filed a shelf registration statement with the SEC in May 2003 to sell up to $300 million in debt. RG&E plans to use the net proceeds from the sale of securities under that shelf registration for general corporate purposes, such as retirement or repurchase of certain of its indebtedness or preferred stock, reduction of short-term debt and additions to working capital. RG&E had $75 million available under a previous shelf registration statement. RG&E currently has $300 million available under the shelf registration statement filed in May 2003.

In July 2003 RG&E paid at maturity $40 million of first mortgage bonds using primarily temporary cash investments and short-term debt.

In September 2003 RG&E issued $75 million of 6 3/8% first mortgage bonds due September 2033 under the shelf registration statements described above. A portion of the net proceeds was used to repay short-term debt, including short-term debt that was issued to pay $40 million of first mortgage bonds that matured in July 2003. RG&E used the remainder of the net proceeds for general corporate purposes.

Quantitative and Qualitative Disclosures about Market Risk

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

The financial instruments held or issued by the company are for purposes other than trading or speculation. Quantitative and qualitative disclosures are discussed as they relate to the following market risk exposure categories: Interest Rate Risk, Commodity Price Risk and Other Market Risk.

Interest Rate Risk The company is exposed to risk resulting from interest rate changes on its variable-rate debt and commercial paper. The company uses interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. Amounts paid and received under those agreements are recorded as adjustments to the interest expense of the specific debt issues. The company estimates that, at December 31, 2003, a 1% change in average interest rates would change annual interest expense for variable rate debt by about $8 million. (See Notes 7, 8 and 13 to the Consolidated Financial Statements.)

The company also uses financial instruments to lock in the treasury rate component of future financings to mitigate risk resulting from interest rate changes.

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

Although CMP has no long-term supply responsibilities, the MPUC can mandate that CMP be a standard-offer provider for supply service should bids by competitive suppliers be deemed unacceptable by the MPUC. CMP has no standard-offer obligations through August 2004. (See CMP Electricity Supply Responsibility.) In September 2001 the MPUC chose Constellation Power Source Maine, LLC as the new supplier of standard-offer electricity to CMP's residential and small commercial standard-offer class for a three-year period beginning March 1, 2002. In January 2004 the MPUC chose suppliers of standard-offer electricity for the six months beginning March 1, 2004, for the medium and large customer classes.

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

NYSEG's current electric rate plan offers retail customers choice in their electricity supply including a variable rate option, an option to purchase electricity supply from an alternative energy company, and a bundled rate option. Approximately 32% of NYSEG's total electric load is now provided by an alternative energy company or at the market price. NYSEG's exposure to fluctuations in the market price of electricity is limited to the load required to serve those customers who select the bundled rate option, which combines delivery and supply service at a fixed price. For 2004 the supply component is based on average electricity forward prices for 2004 during September 2002, plus a 35% margin to cover the costs and risk that NYSEG is assuming by providing a bundled rate option to retail customers. NYSEG actively hedges the load required to serve customers who select the bundled rate option. As of January 30, 2004, NYSEG's load was 94% hedged for on-peak periods and 83% hedged for off-peak periods in 2004. A fluctuation of $1.00 per megawatt-hour in the price of electricity would change earnings by $0.7 million in 2004. The percentage of NYSEG's hedged load is based on NYSEG's load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

RG&E faces commodity price risk that relates to market fluctuations in the price of electricity. Owned electric generation and long-term supply contracts significantly reduce RG&E's exposure to market fluctuations for procurement of its electric supply. As of January 30, 2004, RG&E's load was 94% hedged for on-peak periods and fully hedged for off-peak periods in 2004. A fluctuation of $1.00 per megawatt-hour in the price of summer on-peak electricity would change earnings by $0.2 million in 2004. The percentage of RG&E's hedged load is based on RG&E's load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast. RG&E filed a request with the NYPSC for new electric rates in May 2003. The NYPSC has not ruled on the rate request; therefore, RG&E's current electric rates will remain in effect until a new rate order is issued. A new rate order is expected to be issued in August 2004, subject to a make whole provision to April 2004. (See RG&E 2002 and 2003 Electric and Gas Rate Proceedings.)

While owned generation provides RG&E with a natural hedge against electric price risk, it also subjects it to operating risk. Operating risk is managed through a combination of strict operating and maintenance practices.

All of Energy East's natural gas utilities, except Maine Natural Gas, 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. (See Natural Gas Supply Agreements, NYSEG Natural Gas Rate Plan and Connecticut Regulatory Proceedings.)

NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. The cost or benefit of natural gas futures and forwards is included in the commodity cost when the related sales commitments are fulfilled.

The broad and continued decline in credit quality across the energy supply and marketing industries, combined with the withdrawal of many entities from energy trading operations, could limit the company's ability to purchase electricity and place financial hedges with counterparties that meet its credit requirements. While the company has been successful in implementing its hedging strategies by finding creditworthy counterparties or requiring adequate financial assurances in the form of cash or letters of credit, continued contraction and credit deterioration across the energy supply and marketing industries may adversely affect the company's ability to effectively implement its hedging strategies going forward.

Other Market Risk > The company's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates cause the company to recognize increased or decreased pension income or expense. If the expected return on plan assets were to change by 1/4%, pension income would change by approximately \$6 million. A change of 1/4% in the discount rate would also result in a change in pension income of \$6 million. (See Note 16 to the Consolidated Financial Statements.)

Forward-looking Statements

This Annual Report contains certain forward-looking statements that are based upon management's current expectations and information that is currently available. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. Whenever used in this report, the words "estimate," "expect," "believe," 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 and that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others: the deregulation and continued regulatory unbundling of a vertically integrated industry; the company's ability to compete in the rapidly changing and increasingly competitive electricity and natural gas utility markets; regulatory uncertainty in a politically-charged environment of changing energy prices; the operation of the New York Independent System Operator and ISO New England, Inc.; the operation of a regional transmission organization; the ability to recover nonutility generator and other costs; changes in fuel supply or cost and the success of strategies to satisfy power requirements; the company's ability to expand its products and services, including its energy infrastructure in the Northeast; the company's ability to integrate the operations of Berkshire Energy Resources, CMP Group, Inc., Connecticut Energy Corporation, CTG Resources, Inc. and RGS Energy; the company's ability to achieve enterprise-wide integration synergies; market risk; the ability to obtain adequate and timely rate relief; nuclear or environmental incidents; legal or administrative proceedings; changes in the cost or availability of capital; growth in the areas in which the company is doing business; weather variations affecting customer energy usage; authoritative accounting guidance; acts of terrorists; and other considerations, such as the effect of the volatility in the equity markets on pension benefit cost, that may be disclosed from time to time in the company's publicly disseminated documents and filings. The company undertakes no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

Results of Operations

Due to its merger completed on June 28, 2002, the company's results of operations include RGS Energy beginning with July 2002.

(Thousands, except per share amounts)	**2003**	2002	2001	2003 over 2002 Change	2002 over 2001 Change
Operating Revenues	**$4,593,819**	$3,836,469	$3,749,843	20%	2%
Operating Income	**$650,114**	$592,795	$637,870	10%	(7%)
Income from Continuing Operations	**$207,387**	$190,516	$188,712	9%	1%
Net Income	**$210,446**	$188,603	$187,607	12%	1%
Average Common Shares Outstanding, basic	**145,535**	131,117	116,708	11%	12%
Earnings Per Share from Continuing Operations, basic	**$1.43**	$1.45	$1.62	(1%)	(10%)
Earnings Per Share, basic	**$1.45**	$1.44	$1.61	1%	(11%)
Dividends Paid Per Share	**$1.00**	$.96	$.92	4%	4%

Earnings Per Share

Earnings per share for 2003 increased 1 cent compared to the prior year. Earnings from continuing operations for 2003 were $1.43 per share compared to $1.45 per share for the prior year. During 2003 the company recognized income from discontinued operations of 2 cents per share for two businesses that were sold.

Items contributing to the 2 cent per share decline in earnings from continuing operations for 2003 include lower noncash pension income that reduced earnings 15 cents per share, and an electric rate reduction of $205 million ordered by the NYPSC for NYSEG. The rate reduction, effective March 1, 2002, reduced 2003 earnings 11 cents per share. Other items that reduced earnings in 2003 include: 4 cents per share for lower transmission revenue, 3 cents per share for higher purchased energy costs and 2 cents per share for losses on the retirement of debt. 2003 earnings were also reduced 9 cents per share as a result of a higher effective tax rate due to changes in estimates of income tax accruals in 2002 and 2003. Those decreases were offset by 8 cents per share for higher electric and natural gas deliveries (primarily residential and commercial) due in part to colder winter weather in the first quarter of 2003 partially offset by unfavorable weather in the third and fourth quarters of 2003, and 8 cents per share due to cost control efforts, including lower interest charges. The change in earnings also reflects the negative effects in 2002 of 19 cents per share for restructuring expenses and 6 cents per share for a writedown of the company's investment in NEON Communications.

Earnings per share decreased 17 cents for 2002 compared to 2001. The decrease was primarily the result of an electric rate reduction of $205 million ordered by the NYPSC for NYSEG, effective March 1, 2002, which reduced earnings 50 cents per share. Other items that reduced earnings in 2002 include: 19 cents per share for restructuring expenses; 16 cents per share for higher operating costs, such as the cost of merger integration efforts; 15 cents per share for fewer wholesale sales at lower market prices; 7 cents per share for a loss on early retirement of debt; and 6 cents per share for a writedown of an investment in NEON Communications. Those decreases were significantly offset by increases of 29 cents per share due to lower natural gas costs, which include the benefit of NYSEG's natural gas supply charge that went into effect October 1, 2002; 13 cents per share for higher electric deliveries (primarily residential and commercial) due to warmer summer weather in 2002 and colder winter weather in the fourth quarter of 2002; 19 cents per share due to the elimination of goodwill amortization in 2002; and 39 cents per share due to the effect of a writedown of the investment in NEON Communications in 2001.

Other Items: Other operating expenses include net periodic pension benefit income of $40 million in 2003, $70 million in 2002 and $76 million in 2001. Other operating expenses would have been $30 million lower for 2003 and would have been $6 million lower for 2002 without those decreases in net periodic pension benefit income. Net periodic pension benefit income represented 11% of net income for 2003, 22% for 2002 and 24% for 2001. The earnings effect from changes in pension benefit income reflects any earnings sharing or deferral mechanisms approved by state utility commissions.

Other (income) decreased $4 million in 2003 as a result of lower interest income and $9 million in 2002 primarily due to decreases in miscellaneous income. Other deductions increased $4 million in 2003 and $9 million in 2002 primarily due to losses on retirement of debt. (See Note 1 to the Consolidated Financial Statements.)

Interest charges increased $29 million in 2003, including $27 million because of the addition of RG&E, $15 million because the company recognized as interest expense in 2003 distributions that it had previously recognized as preferred dividends and $14 million that reflects borrowings in June 2002 to finance the company's merger transaction with RGS Energy. (See Notes 1 and 7 to the Consolidated Financial Statements.) Those increases were partially offset by $26 million of interest savings primarily due to refinancings and repayments of first mortgage bonds. Interest charges increased $40 million in 2002, including $34 million because of the addition of RG&E and $17 million for additional borrowings to finance the company's merger transaction with RGS Energy. Those increases were partially offset by $10 million of interest savings due to NYSEG's refinancings and repayments of first mortgage bonds.

The $18 million increase in preferred stock dividends in 2002 includes $16 million due to the company's issuance of trust preferred securities in July 2001 and $2 million because of the addition of RG&E.

The effective tax rate for continuing operations was 36% in 2003 and 31% in 2002. The increase was primarily due to the recognition as interest expense in 2003 distributions that the company had previously recognized as preferred dividends and the effect of depreciation and amortization not normalized related to RG&E for a full year in 2003 compared to six months in 2002. The effective tax rate was 31% in 2002 and 43% in 2001. The decrease was the result of various factors including the elimination of goodwill amortization in 2002, the flow-through effect (in 2001 only) of the sale of NMP2, a lower state income tax rate in 2002 due to combined filing benefits, and an increase in distributions on trust preferred securities that were outstanding for a full year in 2002.

Operating Results for the Electric Delivery Business

(Thousands)	**2003**	2002	2001	2003 over 2002 Change	2002 over 2001 Change
Deliveries – Megawatt-hours					
Retail	**30,593**	26,869	23,238	14%	16%
Wholesale	**5,734**	5,330	6,048	8%	(12%)
Operating Revenues	**$2,758,695**	$2,568,247	$2,504,896	7%	3%
Operating Expenses	**$2,311,801**	$2,119,218	$1,951,475	9%	9%
Operating Income	**$446,894**	$449,029	$553,421	–	(19%)

Operating Revenues > Operating revenues were $190 million higher for 2003 primarily as a result of the addition of RG&E delivery revenues of $343 million. That increase was partially offset by decreases of $35 million due to cooler summer weather for RG&E; $18 million because CMP is no longer the standard-offer provider for the supply of electricity effective March 2002; $24 million due to the combined effects of NYSEG's rate reduction, effective March 2002, and customers choosing alternate suppliers; $46 million due to the elimination in 2002 of the partial amortization of an asset sale gain account that was used to fund a portion of NYSEG's rate reduction effective March 2002; and $11 million due to lower transmission revenues.

The $63 million increase in operating revenues for 2002 was primarily due to the addition of RG&E delivery revenues of $369 million and increased retail deliveries of $33 million primarily due to warmer summer weather in 2002. Those increases were partially offset by reductions of $138 million because CMP is no longer the standard-offer provider for the supply of electricity effective March 2002; $114 million due to a rate reduction for NYSEG, effective March 2002; and $64 million because of lower wholesale revenues primarily due to lower market prices for electricity.

Operating Expenses > The $193 million increase in operating expenses for 2003 was primarily due to the addition of RG&E operating expenses of $282 million. That increase was partially offset by decreases in purchased power costs. Purchased power decreased $18 million because CMP is no longer the standard-offer provider for the supply of electricity effective March 2002 and $12 million because of a decrease in NUG purchases. Purchased power decreased an additional $53 million due to the effect of customers choosing alternate suppliers partially offset by increases caused by both higher market prices and higher retail deliveries because of colder winter weather.

Operating expenses for 2002 increased $168 million. That increase includes $291 million for the addition of RG&E operating expenses; $25 million for restructuring expenses; $15 million of purchased power costs for higher retail deliveries due to warmer summer weather in 2002 and colder winter weather in the fourth quarter of 2002; $15 million for merger integration efforts; $44 million for purchased power costs to replace energy previously provided by NMP2, which was partially offset by a $35 million decrease in certain operating expenses due to the sale of NMP2; and $12 million for the effect of the sale of NYSEG's share of NMP2 in 2001. Those increases were partially offset by decreases including $138 million of electricity purchased because CMP is no longer the standard-offer provider for the supply of electricity, $32 million due to lower market prices for electricity and $9 million due to the elimination of goodwill amortization in 2002.

Operating Results for the Natural Gas Delivery Business

(Thousands)	**2003**	2002	2001	2003 over 2002 Change	2002 over 2001 Change
Deliveries – Dekatherms					
Retail	**212,745**	181,859	148,000	17%	23%
Wholesale	**5,360**	7,074	9,298	(24%)	(24%)
Operating Revenues	**$1,462,127**	$1,032,539	$1,026,124	42%	1%
Operating Expenses	**$1,263,182**	$882,883	$936,606	43%	(6%)
Operating Income	**$198,945**	$149,656	$89,518	33%	67%

Operating Revenues > Operating revenues for 2003 were $430 million higher than the prior year primarily due to the addition of RG&E delivery revenues of $213 million and increases of $50 million due to higher retail deliveries because of colder winter weather in the first quarter of 2003 and $158 million primarily due to higher market prices of natural gas that were passed on to customers.

Operating revenues increased $6 million for 2002. Operating revenues increased $126 million due to the addition of RG&E delivery revenues and $8 million due to increased deliveries primarily because of colder winter weather in the fourth quarter of 2002. Those increases were partially offset by a $98 million decrease because of lower market prices of natural gas that were passed on to customers and a $30 million decrease due to fewer wholesale customers.

Operating Expenses > Operating expenses for 2003 increased $380 million primarily due to the addition of RG&E operating expenses of $178 million, higher natural gas costs of $171 million due to market conditions net of the effect of various rate case deferrals and $28 million due to higher retail deliveries because of colder winter weather in the first quarter of 2003.

Operating expenses decreased $54 million for 2002. That decrease was primarily due to a $159 million decrease in purchased gas costs caused by lower market prices, a $33 million decrease in purchased gas due to fewer wholesale customers and a $15 million decrease due to the elimination of goodwill amortization in 2002. Those decreases were partially offset by increases of $115 million for the addition of RG&E operating expenses, $15 million for restructuring expenses, $9 million for increased purchases of natural gas due to higher deliveries because of colder winter weather in the fourth quarter of 2002, $9 million for higher uncollectible expenses and $6 million for merger integration efforts.

Energy East Corporation
Consolidated Balance Sheets

December 31 (Thousands)	2003	2002
Assets		
Current Assets		
Cash and cash equivalents	**$113,187**	$250,490
Special deposits	**34,669**	47,643
Accounts receivable, net	**753,328**	737,876
Fuel, at average cost	**159,163**	117,678
Materials and supplies, at average cost	**22,491**	22,953
Accumulated deferred income tax benefits, net	**26,262**	20,151
Prepayments and other current assets	**81,746**	86,167
Total Current Assets	**1,190,846**	1,282,958
Utility Plant, at Original Cost		
Electric	**5,992,001**	5,803,576
Natural gas	**2,405,795**	2,347,011
Common	**361,737**	360,776
	8,759,533	8,511,363
Less accumulated depreciation	**3,216,927**	3,201,158
Net Utility Plant in Service	**5,542,606**	5,310,205
Construction work in progress	**235,503**	179,557
Total Utility Plant	**5,778,109**	5,489,762
Other Property and Investments, Net	**452,843**	452,710
Regulatory and Other Assets		
Nuclear plant obligations	**414,432**	524,679
Unfunded future income taxes	**254,977**	234,487
Unamortized loss on debt reacquisitions	**47,509**	45,353
Environmental remediation costs	**122,846**	106,262
Nonutility generator termination agreements	**106,631**	116,782
Asset retirement obligation	**163,530**	–
Other	**407,432**	370,354
Total regulatory assets	**1,517,357**	1,397,917
Goodwill, net	**1,533,123**	1,518,173
Prepaid pension benefits	**608,933**	540,426
Other	**225,221**	262,401
Total other assets	**2,367,277**	2,321,000
Total Regulatory and Other Assets	**3,884,634**	3,718,917
Total Assets	**$11,306,432**	$10,944,347

The notes on pages 29 through 51 are an integral part of the financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31 (Thousands)	2003	2002
Liabilities		
Current Liabilities		
Current portion of preferred stock of subsidiary subject to mandatory redemption requirements	$1,250	–
Current portion of long-term debt	30,989	$545,404
Notes payable	308,406	322,200
Accounts payable and accrued liabilities	339,812	361,499
Interest accrued	48,989	44,310
Taxes accrued	43,710	30,036
Other	191,873	200,927
Total Current Liabilities	965,029	1,504,376
Regulatory and Other Liabilities		
Accrued removal obligation	731,621	676,006
Deferred income taxes	181,211	147,018
Gain on sale of generation assets	129,640	152,648
Pension benefits	51,970	67,205
Other	96,509	104,937
Total regulatory liabilities	1,190,951	1,147,814
Deferred income taxes	853,489	770,788
Nuclear plant obligations	277,643	314,013
Other postretirement benefits	408,903	391,049
Asset retirement obligation	437,076	–
Environmental remediation costs	145,446	133,933
Other	346,630	408,841
Total other liabilities	2,469,187	2,018,624
Total Regulatory and Other Liabilities	3,660,138	3,166,438
Debt owed to subsidiary holding solely parent debentures	355,670	–
Preferred stock of subsidiary subject to mandatory redemption requirements	23,750	–
Other long-term debt	3,638,426	3,351,959
Total long-term debt	4,017,846	3,351,959
Total Liabilities	8,643,013	8,022,773
Commitments	–	–
Preferred Stock of Subsidiaries		
Company-obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures	–	345,000
Subject to mandatory redemption requirements	–	25,000
Redeemable solely at the option of subsidiaries	91,095	90,962
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 146,262 shares outstanding at December 31, 2003, and 144,966 shares outstanding at December 31, 2002)	1,463	1,455
Capital in excess of par value	1,458,802	1,447,664
Retained earnings	1,126,457	1,061,428
Accumulated other comprehensive income (loss)	(11,214)	(34,167)
Deferred compensation	(2,820)	–
Treasury stock, at cost (13 shares at December 31, 2003, and 574 shares at December 31, 2002)	(364)	(15,768)
Total Common Stock Equity	2,572,324	2,460,612
Total Liabilities and Stockholders' Equity	$11,306,432	$10,944,347

The notes on pages 29 through 51 are an integral part of the financial statements.

Energy East Corporation
Consolidated Statements of Income

Year Ended December 31 (Thousands, except per share amounts)	2003	2002	2001
Operating Revenues			
Sales and services	**$4,593,819**	$3,836,469	$3,749,843
Operating Expenses			
Electricity purchased and fuel used in generation	**1,329,443**	1,276,087	1,334,507
Natural gas purchased	**1,001,649**	603,258	694,038
Other operating expenses	**837,953**	691,987	560,572
Maintenance	**202,918**	160,230	139,321
Depreciation and amortization	**301,264**	242,111	203,310
Other taxes	**270,478**	229,434	192,505
Restructuring expenses	**-**	40,567	-
Gain on sale of generation assets	**-**	-	(84,083)
Deferral of asset sale gain	**-**	-	71,803
Total Operating Expenses	**3,943,705**	3,243,674	3,111,973
Operating Income	**650,114**	592,795	637,870
Writedown of Investment	**-**	12,209	78,422
Other (Income)	**(22,073)**	(26,496)	(35,202)
Other Deductions	**33,302**	29,307	20,216
Interest Charges, Net	**284,802**	256,292	216,388
Preferred Stock Dividends of Subsidiaries	**19,009**	32,129	14,455
Income from Continuing Operations Before Income Taxes	**335,074**	289,354	343,591
Income Taxes	**127,687**	98,838	154,879
Income from Continuing Operations	**207,387**	190,516	188,712
Discontinued Operations			
Loss from businesses sold (including loss on disposal in 2003 of $13,360)	**(9,953)**	(2,227)	(1,605)
Income taxes (benefits)	**(13,012)**	(314)	(500)
Income (Loss) from Discontinued Operations	**3,059**	(1,913)	(1,105)
Net Income	**$210,446**	$188,603	$187,607
Earnings Per Share from Continuing Operations, basic	**$1.43**	$1.45	$1.62
Earnings Per Share from Continuing Operations, diluted	**$1.42**	$1.45	$1.62
Total Earnings Per Share, basic	**$1.45**	$1.44	$1.61
Total Earnings Per Share, diluted	**$1.44**	$1.44	$1.61
Average Common Shares Outstanding, basic	**145,535**	131,117	116,708
Average Common Shares Outstanding, diluted	**145,730**	131,117	116,708

The notes on pages 29 through 51 are an integral part of the financial statements.

Energy East Corporation
Consolidated Statements of Cash Flows

Year Ended December 31	2003	2002	2001
(Thousands)			
Operating Activities			
Net income	**$210,446**	$188,603	$187,607
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	**419,237**	255,782	247,847
Income taxes and investment tax credits deferred, net	**103,236**	43,564	4,588
Restructuring expenses	**-**	40,567	-
Gain on sale of generation assets	**-**	-	(84,083)
Deferral of asset sale gain	**-**	-	71,803
Pension income	**(40,128)**	(70,189)	(76,229)
Writedown of investment	**-**	12,209	78,422
Changes in current operating assets and liabilities			
Accounts receivable, net	**(56,188)**	(24,247)	125,121
Sale of accounts receivable program	**-**	-	(152,000)
Inventory	**(50,775)**	6,111	(25,445)
Prepayments and other current assets	**8,732**	(3,998)	3,119
Accounts payable and accrued liabilities	**(3,351)**	5,551	(123,832)
Other current liabilities	**15,941**	5,866	(51,373)
Other assets	**(134,472)**	(66,279)	(44,163)
Other liabilities	**9,737**	16,896	(6,848)
Net Cash Provided by Operating Activities	**482,415**	410,436	154,534
Investing Activities			
Acquisitions, net of cash acquired	**-**	(681,397)	-
Utility plant additions	**(289,320)**	(224,450)	(208,677)
Sale of generation assets	**-**	59,442	59,441
Other property and investments additions	**(39,060)**	(29,177)	(30,271)
Other property and investments sold	**72,478**	12,138	18,967
Special deposits	**6,313**	(5,166)	19,909
Other	**(6,678)**	1,490	(19,344)
Net Cash Used in Investing Activities	**(256,267)**	(867,120)	(159,975)
Financing Activities			
Issuance of common stock	**4,234**	2,574	740
Repurchase of common stock	**-**	(2,139)	(24,116)
Issuance of mandatorily redeemable trust preferred securities	**-**	-	345,000
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	**(242,066)**	(435,720)	(1,890)
Long-term note issuances	**504,769**	767,807	355,553
Long-term note repayments	**(488,654)**	(97,124)	(29,965)
Notes payable three months or less, net	**(7,044)**	166,702	(269,012)
Notes payable issuances	**11,000**	28,400	54,445
Notes payable repayments	**(17,750)**	(50,154)	(31,045)
Dividends on common stock	**(127,940)**	(110,186)	(100,881)
Net Cash (Used in) Provided by Financing Activities	**(363,451)**	270,160	298,829
Net (Decrease) Increase in Cash and Cash Equivalents	**(137,303)**	(186,524)	293,388
Cash and Cash Equivalents, Beginning of Year	**250,490**	437,014	143,626
Cash and Cash Equivalents, End of Year	**$113,187**	$250,490	$437,014

The notes on pages 29 through 51 are an integral part of the financial statements.

Energy East Corporation
Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Common Stock Outstanding $.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Treasury Stock	Total
Balance, January 1, 2001	117,656	$1,191	$871,078	$918,016	$(34,823)	–	$(38,940)	$1,716,522
Net income				187,607				187,607
Other comprehensive income, net of tax					12,488			12,488
Comprehensive income								200,095
Common stock dividends declared ($.92 per share)				(107,342)				(107,342)
Common stock issued – dividend reinvestment and stock purchase plan	368	4	7,197					7,201
Common stock repurchased	(1,306)	(13)	(24,103)					(24,116)
Capital stock issue expense			(11,498)					(11,498)
Amortization of capital stock issue expense			315					315
Balance, December 31, 2001	116,718	1,182	842,989	998,281	(22,335)	–	(38,940)	1,781,177
Net income				188,603				188,603
Other comprehensive income, net of tax					(11,832)			(11,832)
Comprehensive income								176,771
Common stock dividends declared ($.96 per share)				(125,456)				(125,456)
Common stock issued – merger transaction	27,509	275	611,807					612,082
Common stock issued – dividend reinvestment and stock purchase plan	853		17,844					17,844
Common stock repurchased	(114)	(1)	(2,138)					(2,139)
Capital stock issue expense			(52)					(52)
Treasury stock transactions, net		(1)	(23,171)				23,172	–
Amortization of capital stock issue expense			385					385
Balance, December 31, 2002	144,966	1,455	1,447,664	1,061,428	(34,167)	–	(15,768)	2,460,612
Net income				210,446				210,446
Other comprehensive income, net of tax					22,953			22,953
Comprehensive income								233,399
Common stock dividends declared ($1.00 per share)				(145,417)				(145,417)
Common stock issued – dividend reinvestment and stock purchase plan	1,064	8	21,703					21,711
Common stock issued – restricted stock plan	229		(1,893)			$(4,401)	6,294	–
Amortization of deferred compensation under restricted stock plan						1,581		1,581
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	3		(9,046)				9,110	64
Amortization of capital stock issue expense			385					385
Balance, December 31, 2003	146,262	$1,463	$1,458,802	$1,126,457	$(11,214)	$(2,820)	$(364)	$2,572,324

The notes on pages 29 through 51 are an integral part of the financial statements.

NOTE 1 Significant Accounting Policies

Background > Energy East Corporation (Energy East or the company) is a registered public utility holding company under the Public Utility Holding Company Act of 1935. Energy East is a super-regional energy services and delivery company with operations in New York, Connecticut, Massachusetts, Maine and New Hampshire and corporate offices in New York and Maine. Its wholly-owned subsidiaries – and their principal operating utilities – are: Berkshire Energy Resources – The Berkshire Gas Company; CMP Group, Inc. (CMP Group) – Central Maine Power Company (CMP); Connecticut Energy Corporation (CNE) – The Southern Connecticut Gas Company (SCG); CTG Resources, Inc. (CTG Resources) – Connecticut Natural Gas Corporation (CNG); and RGS Energy Group, Inc. (RGS Energy) – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E).

Accounts receivable > Accounts receivable include unbilled revenues of $219 million at December 31, 2003, and $237 million at December 31, 2002, and are shown net of an allowance for doubtful accounts of $53 million at December 31, 2003, and $59 million at December 31, 2002. Bad debt expense was $48 million in 2003, $46 million in 2002 and $34 million in 2001. Bad debt expense for 2003 includes RGS Energy for a full year and for 2002 includes RGS Energy beginning July 1, 2002.

In August 2001 NYSEG terminated its agreement to sell, with limited recourse, undivided percentage interests in certain of its accounts receivable from customers. The agreement allowed NYSEG to receive up to $152 million from the sale of such interests. All fees related to the agreement beginning April 1, 2001, are included in interest expense and were approximately $3 million. Fees related to the sale of accounts receivable through March 31, 2001, are included in other deductions and were approximately $2 million in 2001. NYSEG's sale of accounts receivable before the agreement was terminated did not constitute a securitization transaction because the accounts receivable were not transferred to a special purpose entity, and therefore, were not transformed into securities.

Basic and diluted earnings per share > Basic earnings per share (EPS) is determined by dividing net income by the weighted-average number of shares of common stock outstanding during the year. 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 stock appreciation rights (SARs). However, all stock options are issued in tandem with SARs and, historically, substantially all stock option plan participants have exercised the SARs instead of the stock options. The numerator used in calculating both basic and diluted EPS for each period is the reported net income. The reconciliation of basic and dilutive average common shares for each year follows:

Year Ended December 31 (Thousands)	2003	2002	2001
Basic average common shares outstanding	**145,535**	131,117	116,708
Restricted stock awards	**195**	–	–
Potentially dilutive common shares	**197**	215	198
Options issued with SARs	**(197)**	(215)	(198)
Dilutive average common shares	**145,730**	131,117	116,708

Options to purchase shares of common stock are excluded from the determination of EPS when the exercise price of the options is greater than the average market price of the common shares during the year. Shares excluded from the EPS calculation were: 2.9 million in 2003, 4.7 million in 2002 and 2.1 million in 2001.

On February 13, 2003, the company awarded 229,230 shares of its common stock, issued out of its treasury stock, to certain employees under its Restricted Stock Plan. (See Note 14.)

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

Supplemental Disclosure of Cash Flows Information	2003	2002	2001
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	**$245,223**	$238,305	$208,431
Income taxes, net of benefits received	**$(12,879)**	$54,418	$113,274
Acquisitions:			
Fair value of assets acquired	–	$3,264,093	–
Liabilities assumed	–	(1,826,528)	–
Preferred stock of subsidiaries	–	(72,000)	–
Common stock issued	–	(612,082)	–
Cash acquired	–	(72,086)	–
Net cash paid for acquisitions	–	$681,397	–

Decommissioning expense > Other operating expenses include nuclear decommissioning expense accruals, which result in corresponding decreases in the regulatory asset for the asset retirement obligation. Contributions are made to the decommissioning trust funds, which are included in other property and investments. Increases in the fair value of fund investments also result in decreases in the regulatory asset for the asset retirement obligation.

Depreciation and amortization > The company determines depreciation expense substantially using straight-line rates, 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 – 52 years, distribution property – 43 years, generation property – 45 years, gas production property – 25 years, gas storage property – 24 years, and other property – 29 years. RG&E determines depreciation expense for 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 six years for nuclear facilities to 32 years for hydroelectric facilities. The company's depreciation accruals were equivalent to 3.4% of average depreciable property for 2003; 3.5% for 2002, which was weighted for the effect of the merger completed in June 2002; and 3.1% for 2001.

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

Goodwill > The excess of the cost over fair value of net assets of purchased businesses is recorded as goodwill. The company evaluates the carrying value of goodwill for impairment at least annually and on an interim basis if there are indications that goodwill might be impaired. Any impairment would be recognized when the fair value of goodwill is less than its carrying value. Goodwill was amortized on a straight-line basis over five to 40 years until December 31, 2001. (See Note 5.)

Income taxes > The company files a consolidated federal income tax return. Income taxes are allocated among Energy East and its subsidiaries in proportion to their contribution to consolidated taxable income. SEC regulations require that no Energy East subsidiary pay more income taxes than it would pay if a separate income tax return were to be filed. The determination and allocation of the 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. Investment tax credits (ITC) are amortized over the estimated lives of the related assets.

Other (Income) and Other Deductions >

Year Ended December 31 (Thousands)	2003	2002	2001
Dividends	**–**	$(233)	$(1,844)
Interest income	**$(6,529)**	(13,174)	(13,125)
Noncash returns	**(1,602)**	(6,693)	(2,404)
Allowance for funds used during construction	**(1,965)**	(1,401)	(652)
Gain from the sale of nonutility property	**(347)**	(231)	(3,628)
Earnings from equity investments	**(4,702)**	(4,631)	(7,162)
Miscellaneous	**(6,928)**	(133)	(6,387)
Total other (income)	**$(22,073)**	$(26,496)	$(35,202)
Retirement of debt	**$22,784**	$16,145	–
Fees on sale of accounts receivable	**–**	–	$2,495
Miscellaneous	**10,518**	13,162	17,721
Total other deductions	**$33,302**	$29,307	$20,216

Principles of consolidation > These financial statements consolidate the company's majority-owned subsidiaries after eliminating intercompany transactions, except variable interest entities for which the company is not the primary beneficiary.

Reclassifications > Certain amounts have been reclassified on the consolidated financial statements to conform to the 2003 presentation.

Regulatory assets and liabilities > Pursuant to Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation, the company capitalizes, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. It also records, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. 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 the company's current rate plans. The company earns a return on substantially all regulatory assets for which funds have been spent.

Revenue recognition > The company recognizes revenues upon delivery of energy and energy-related products and services to its 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 any purchase and sales arrangements for power with the ISO New England, the New England Power Pool, or any other independent system operator or similar entity. All of CMP's power entitlements under its NUG and other purchase power contracts are sold to unrelated third parties under bilateral contracts for the period March 1, 2002, through February 28, 2005.

NYSEG and RG&E enter into power purchase and sales transactions with the NYISO. When electricity from owned generation is sold to the NYISO, and subsequently repurchased from the NYISO to serve their customers, the transactions are recorded on a net basis in the consolidated statements of income.

Risk management > All of Energy East's natural gas utilities except Maine Natural Gas 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. The company uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. The cost or benefit of natural gas futures and forwards is included in the commodity cost when the related sales commitments are fulfilled.

The company uses electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity. The cost or benefit of those contracts is included in the amount expensed for electricity purchased when the electricity is sold.

The company uses interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. It records amounts paid and received under the agreements as adjustments to the interest expense of the specific debt issues. The company also uses financial instruments to lock in the treasury rate component of future financings to mitigate risk resulting from interest rate changes.

The company does not hold or issue financial instruments for trading or speculative purposes.

The company recognizes the fair value of its natural gas futures and forwards, financial electricity contracts and interest rate agreements as assets or liabilities. The company's derivative asset was $65 million at December 31, 2003, and $80 million at December 31, 2002, and its derivative liability was $3 million at December 31, 2003, and $9 million at December 31, 2002. All of the arrangements are designated as cash flow hedging instruments except for the company's $250 million fixed-to-floating interest rate swap agreement, which is designated as a fair value hedge. Changes in the fair value of the cash flow hedging instruments are recognized in other comprehensive income until the underlying transaction occurs. When the underlying transaction occurs, the amounts in accumulated other comprehensive income are reported on the consolidated statements of income. Changes in the fair value of the interest rate swap agreement are reported on the consolidated statements of income in the same period as the offsetting change in the fair value of the underlying debt instrument.

The company uses quoted market prices to fair value derivatives and adjusts for volatility and inflation when the period of the derivative exceeds the period for which market prices are readily available.

As of December 31, 2003, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted transactions is 72 months. The company estimates that gains of $22 million will be reclassified from accumulated other comprehensive income into earnings in 2004, as the underlying transactions occur.

The company has commodity purchase and sales contracts for both capacity and energy that have been designated and qualify for the normal purchases and normal sales exception in Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement 133), as amended.

Statement 143 > In June 2001 the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. Statement 143 requires an entity to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and to capitalize the cost by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement the entity either settles the obligation at its recorded amount or incurs a gain or a loss. For rate-regulated entities, any timing differences between rate recovery and book expense would be deferred as either a regulatory asset or a regulatory liability.

The company's adoption of Statement 143 as of January 1, 2003, did not have a material effect on its financial position or results of operations. There was no effect on net income. The company recognized various amounts on its balance sheets. Changes in the assumptions underlying the items shown in the following table could affect the balance sheet amounts and future costs related to the obligations.

Substantially all of Energy East's asset retirement obligation is related to Ginna.

As of January 1, 2003	NYSEG	RG&E	Other	Consolidated Energy East
(Thousands)				
Asset retirement obligation	$(539)	$(413,988)	$(942)	$(415,469)
Regulatory asset	$350	$139,611	$942	$140,903
Regulatory liability	$(3,689)	$(635)	–	$(4,324)
Increase in utility plant	$30	$74,064	–	$74,094
Decrease in accumulated depreciation	$3,848	$200,948	–	$204,796

Statement 143 provides that if the requirements of Statement 71 are met, a regulatory liability should be recognized for the difference between removal costs collected in rates and actual costs incurred. In previous years, those amounts were included in accumulated depreciation in accordance with industry practice. Accrued removal obligations totaling approximately $732 million as of December 31, 2003 ($80 million for CMP, $304 million for NYSEG, $185 million for RG&E and $163 million for Other), and $676 million as of December 31, 2002 ($74 million for CMP, $286 million for NYSEG, $169 million for RG&E and $147 million for Other), that had previously been embedded within accumulated depreciation were reclassified as a regulatory liability.

Statement 150 > In May 2003 the FASB issued Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. Statement 150 requires that certain financial instruments be classified as liabilities in statements of financial position. Under previous guidance such instruments could be classified as equity. In accordance with Statement 150, Energy East and RG&E are required to classify their mandatorily redeemable preferred stock as a liability on their statements of financial position, which they had previously classified as equity, and to recognize as interest expense distributions that they had previously recognized as dividends. RG&E has $25 million of mandatorily redeemable preferred stock that is consolidated by Energy East. Energy East and RG&E adopted Statement 150 as of July 1, 2003. The adoption of Statement 150 did not have a material effect on Energy East's or RG&E's financial position or results of operations.

FIN 46R > In December 2003 the FASB issued its revised FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51 (FIN 46R). FIN 46R 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 46R requires a business enterprise to consolidate a variable interest entity if that enterprise has a variable interest that will absorb a majority of the entity's expected losses. The company has a variable interest in Energy East Capital Trust I, a Delaware business trust that is a wholly-owned finance subsidiary of the company. Based on the trust's structure the company is not considered the primary beneficiary of the trust. The company had consolidated the trust under ARB No. 51. The company adopted the provisions of FIN 46R related to special purpose entities as of December 31, 2003, and ceased consolidating the trust as of December 31, 2003.

CMP and NYSEG have independent, ongoing, long-term power purchase contracts with NUGs. (See Note 10.) In accordance with FIN 46R, the company is evaluating if either CMP or NYSEG has a variable interest in any NUG and, to the extent that either company has a variable interest, whether it is a primary beneficiary. To the extent that CMP or NYSEG is a primary beneficiary of a NUG, consolidation would be required at March 31, 2004, unless the company is unable to obtain sufficient information to do so. CMP and NYSEG were not involved in the formation of any NUGs, do not have ownership interests in any NUGs and may not be able to obtain sufficient information from the NUGs to determine if either company is a primary beneficiary. The company is presently unable to determine the effect on its financial statements, if any, of applying FIN 46R to CMP's and NYSEG's power purchase contracts with NUGs.

As of December 31, 2003, the company no longer reflects company-obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures on its Consolidated Balance Sheet, but instead reports its junior subordinated debt held by the trust as long-term debt owed to subsidiary holding solely parent debentures. (See Note 7.)

Utility plant > The company charges repairs and minor replacements to operating expense accounts, and capitalizes renewals and betterments, including certain indirect costs. The original cost of utility plant retired or otherwise disposed of is charged to accumulated depreciation.

NOTE 2 Sale of Other Businesses

In keeping with its focus on regulated electric and natural gas delivery businesses, during the past few years the company has been systematically exiting certain noncore businesses. In May 2003 Berkshire Propane, Inc., a subsidiary of Berkshire Energy Resources, sold about one-fourth of its assets and customers for approximately book value. Berkshire Energy Resources is a wholly-owned subsidiary of Energy East. In October 2003 Energetix sold its Griffith Oil Co., Inc. subsidiary at an after tax gain of $3 million and in November 2003 Berkshire

Propane, Inc. sold its remaining assets at an after tax loss of $2 million. Both businesses were reported in the company's Other business segment. In 2003 the company recognized income from discontinued operations of $3 million or 2 cents per share for the two businesses.

On August 12, 2002, Berkshire Service Solutions, Inc., an energy service provider and a subsidiary of Berkshire Energy Resources, was sold at an after tax loss of approximately $2 million.

The results of discontinued operations of the businesses sold were:

Year Ended December 31	2003	2002	2001
(Thousands)			
Griffith Oil Co., Inc.			
Revenues	**$321,447**	$164,464	–
Pretax (loss) income from discontinued operations (including loss on disposal in 2003 of $11,553)	**$(7,798)**	$1,786	–
Income taxes (benefits) (including realization of capital loss deduction in 2003 of $8,114)	**(13,387)**	882	–
Income from discontinued operations	**$5,589**	$904	–
Berkshire Propane, Inc.			
Revenues	**$5,494**	$6,051	$6,562
Pretax (loss) income from discontinued operations (including loss on disposal in 2003 of $1,807)	**$(2,155)**	$74	$(259)
Income taxes (benefits)	**375**	30	(21)
(Loss) income from discontinued operations	**$(2,530)**	$44	$(238)
Berkshire Service Solutions, Inc.			
Revenues	**-**	$1,934	$3,383
Pretax loss from discontinued operations	**-**	$(4,087)	$(1,346)
Income taxes (benefits)	**-**	(1,226)	(479)
Loss from discontinued operations	**-**	$(2,861)	$(867)
Total income (loss) from discontinued operations	**$3,059**	$(1,913)	$(1,105)

The major classes of assets and liabilities at the date of sale of the businesses were:

	Griffith Oil Co., Inc.	Berkshire Propane, Inc.	Berkshire Service Solutions, Inc.
(Thousands)			
Assets			
Other property and investments, net	$111,950	$4,809	$287
Liabilities			
Current liabilities	$32,248	$447	$322

NOTE 3 Restructuring

In the fourth quarter of 2002 Energy East recorded $41 million of restructuring expenses related to its voluntary early retirement and involuntary severance programs at six of its operating companies. The $41 million of restructuring expenses included $5 million for CMP, $26 million for NYSEG and a total of $10 million for Berkshire Gas, CNG and SCG. The restructuring expenses would have been $36 million higher, however RG&E was required by an NYPSC order approving RGS Energy's merger with the company to defer its portion of the restructuring charge for future recovery in rates. The employee positions affected by the restructuring were identified in the fourth quarter of 2002. The restructuring expenses reduced the company's 2002 net income by $24 million or 19 cents per share. Included in those amounts were $20 million for the voluntary early retirement program that will be paid from the companies' pension plans and $3 million for the involuntary severance program, primarily for salaried employees, and $1 million for other associated costs. During 2003 the entire related involuntary severance liability of $9 million was paid, including $4 million that was deferred for recovery by RG&E.

The voluntary early retirement program resulted in a reduction of 486 employees in the first quarter of 2003. Collectively the voluntary early retirement and involuntary severance programs resulted in a reduction in overall employee headcount of 678, or 8%, in 2003, including 79 from CMP, 255 from NYSEG and 253 from RG&E.

The company has consolidated the accounting and finance functions of five of its operating companies to one location and has reorganized and relocated the accounting and finance functions of its management subsidiary. In connection with this latest restructuring, the company began to recognize an expected $4 million total liability for an enhanced severance program for certain accounting and finance employees who will be employed through March 31, 2004. Approximately $3 million of the expected total liability will be incurred by the electric delivery business and $1 million by the natural gas delivery business. During the fourth quarter of 2003, 40% of the total liability for each business segment was charged to other operating expenses and represents the company's cumulative expense and liability as of December 31, 2003.

NOTE 4 Acquisition of RGS Energy Group

Due to the completion of the company's merger with RGS Energy on June 28, 2002, the company's consolidated financial statements include RGS Energy's results beginning with July 2002. RGS Energy did not push goodwill down to RG&E. As of December 31, 2002, $29 million of the purchase price for RGS Energy was allocated to intangible assets, based on an appraisal.

The following pro forma information for the company for the years ended December 31, 2002 and 2001, which is based on unaudited data, gives effect to the company's merger with RGS Energy as if it had been completed at the beginning of each period presented. This information does not reflect future revenues or cost savings that may result from the merger and is not indicative of actual results of operations had the merger occurred at the beginning of the periods presented or of results that may occur in the future.

Year Ended December 31	2002	2001
(Thousands, except per share amounts)		
Operating revenues	$4,690,489	$5,290,279
Net income	$201,521	$262,741
Earnings per share of common stock, basic	$1.39	$1.82

Pro forma adjustments reflected in the amounts presented include: (1) adjusting RGS Energy's nonutility assets to fair value based on an independent appraisal, (2) adjusting depreciation and amortization of assets to the accounting base recognized in recording the combination, (3) elimination of amortization of goodwill, (4) amortization of other intangible assets with finite lives, (5) elimination of merger costs, (6) additional interest expense and preferred stock dividends due to the issuance of merger-related debt and securities, (7) adjustments for estimated tax effects of the above adjustments and (8) additional common shares issued in connection with the merger. The pro forma results include a loss of 19 cents per share for restructuring expenses and the writedown of CMP Group's investment in NEON Communications of 6 cents per share in 2002 and 39 cents per share in 2001. The pro forma results of operations for 2002 include the results of operations of RGS Energy for the six months ended June 30, 2002, as follows: Operating revenues – $681,571, Operating expenses – $615,851, Operating income – $65,720, Income before income taxes – $36,850, and Net income – $15,550.

NOTE 5 Goodwill and Other Intangible Assets

The company no longer amortizes goodwill effective January 1, 2002, and does not amortize intangible assets with indefinite lives (unamortized intangible assets). The company tests both goodwill and unamortized intangible assets for impairment at least annually. The company amortizes intangible assets with finite lives (amortized intangible assets) and reviews them for impairment. Annual impairment testing was completed and it was determined that there was no impairment of goodwill or unamortized intangible assets for the companies at September 30, 2003.

Changes in the carrying amount of goodwill, by operating segment, for the year ended December 31, 2003, are shown in the table below. The increase in goodwill related to excess earnings was recorded by RGS Energy. It resulted from the refund to customers of RG&E's excess earnings recorded prior to its acquisition by Energy East, as part of RG&E's 2002 electric and gas rate proceeding, which was a preacquisition contingency related to RG&E.

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
Balance, January 1, 2003	$819,992	$677,952	$20,229	$1,518,173
Goodwill related to additional excess earnings	26,486	–	–	26,486
Goodwill related to businesses sold	–	–	(7,799)	(7,799)
Preacquisition income tax and other adjustments	(1,947)	(833)	(957)	(3,737)
Balance, December 31, 2003	$844,531	$677,119	$11,473	$1,533,123

Other Intangible Assets > The company's unamortized intangible assets had a carrying amount of $10 million at December 31, 2003, and primarily consisted of pension assets, and had a carrying amount of $17 million at December 31, 2002, and primarily consisted of trade names and pension assets. The company's amortized intangible assets had a gross carrying amount of $31 million at December 31, 2003, and $47 million at December 31, 2002, and primarily consisted of investments in pipelines and customer lists. The decreases in the carrying amounts of intangible assets in 2003 represent assets associated with businesses sold. Accumulated amortization was $12 million at December 31, 2003, and $15 million at December 31, 2002. Estimated amortization expense for intangible assets for the next five years is approximately $3 million for 2004, $2 million for 2005, and $1 million each year for 2006 through 2008.

Transitional Information > Results of operations information for the company as though goodwill had not been amortized for all years presented is:

Year Ended December 31	2003	2002	2001
(Thousands, except per share data)			
Reported net income	**$210,446**	$188,603	$187,607
Add back: goodwill amortization	**–**	–	25,379
Adjusted net income	**$210,446**	$188,603	$212,986
Reported basic earnings per share	**$1.45**	$1.44	$1.61
Add back: goodwill amortization	**–**	–	.22
Adjusted basic earnings per share	**$1.45**	$1.44	$1.83

NOTE 6 Income Taxes

Year Ended December 31	2003	2002	2001
(Thousands)			
Current	**$19,420**	$52,407	$148,016
Deferred, net			
Accelerated depreciation	**44,544**	19,120	12,452
Pension benefits	**38,426**	36,864	31,179
Statement 106 postretirement benefits	**(7,119)**	(4,627)	(4,079)
Demand-side management	**(650)**	(2,189)	(9,295)
Asset sale gain account amortization	**(12,325)**	29,367	–
Restructuring expenses	**3,615**	(15,816)	–
Contract termination payments	**30,801**	122	102
Miscellaneous	**14,626**	(13,886)	(21,381)
ITC	**(3,651)**	(2,524)	(2,115)
Total for Continuing Operations	**$127,687**	$98,838	$154,879

The company's effective tax rate differed from the statutory rate of 35% due to the following:

Year Ended December 31 (Thousands)	2003	2002	2001
Tax expense at statutory rate	**$123,929**	$112,523	$125,301
Depreciation and amortization not normalized	**10,715**	5,125	26,373
ITC amortization	**(3,651)**	(2,524)	(2,115)
Trust preferred securities	**(4,978)**	(9,932)	(4,389)
State taxes, net of federal benefit	**12,254**	9,793	14,881
Other, net	**(10,582)**	(16,147)	(5,172)
Total for Continuing Operations	**$127,687**	$98,838	$154,879

The effective tax rate for continuing operations was 36% in 2003 and 31% in 2002. The increase was primarily due to the recognition as interest expense in 2003 distributions that the company had previously recognized as preferred dividends and the effect of depreciation and amortization not normalized related to RG&E for a full year in 2003 compared to six months in 2002. The effective tax rate was 31% in 2002 and 43% in 2001. The decrease was the result of various factors including the elimination of goodwill amortization in 2002, the flow-through effect (in 2001 only) of the sale of NMP2, a lower state income tax rate in 2002 due to combined filing benefits, and an increase in distributions on trust preferred securities that were outstanding for a full year in 2002.

The company's deferred tax assets and liabilities consisted of the following:

December 31 (Thousands)	2003	2002
Current Deferred Tax Assets	**$26,262**	$20,151
Noncurrent Deferred Tax Liabilities		
Depreciation	**$821,783**	$750,739
Unfunded future income taxes	**144,705**	129,481
Accumulated deferred ITC	**41,494**	45,039
Deferred gain on sale of generation assets	**35,211**	63,969
Pension benefits	**151,559**	87,717
Statement 106 postretirement benefits	**(84,327)**	(92,182)
Nuclear decommissioning	**(49,681)**	(44,093)
Other	**(26,044)**	(22,864)
Total Noncurrent Deferred Tax Liabilities	**1,034,700**	917,806
Less amounts classified as regulatory liabilities		
Deferred income taxes	**181,211**	147,018
Noncurrent Deferred Income Taxes	**$853,489**	$770,788

Energy East and its subsidiaries have no federal tax credit carryforwards. A subsidiary of Energy East has a loss carryforward of less than $1 million, with no valuation allowance.

NOTE 7 Long-term Debt

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

Energy East Capital Trust I is a Delaware business trust that is a wholly-owned finance subsidiary of the company. Based on the trust's structure the company is not considered the primary beneficiary of the trust and as of December 31, 2003, the company no longer consolidates the trust. (See Note 1.) The assets of the trust consist of the company's 8 1/4% junior subordinated debt securities. The trust has issued $345 million of mandatorily redeemable trust preferred securities that are 8 1/4% Capital Securities. The company has fully and unconditionally guaranteed the trust's payment obligations with respect to the Capital Securities.

Preferred stock of subsidiary subject to mandatory redemption requirements > The preferred stock subject to mandatory redemption requirements is RG&E's 6.60% Series V, Par Value $100, with a redemption price per share of $100 and 250,000 shares authorized and outstanding. This series is subject to a mandatory sinking fund sufficient to redeem, at par, on March 1 of each year from 2004 through 2008, 12,500 shares, and on March 1, 2009, the balance of the shares. RG&E has the option to redeem up to an additional 12,500 shares on the same terms and dates as applicable to the mandatory sinking fund. In the event RG&E should be in arrears in the sinking fund requirement, RG&E may not redeem or pay dividends on any stock subordinate to the preferred stock.

Voting rights: If preferred stock dividends on RG&E's 6.60% Series V preferred stock are in default in an amount equivalent to four full quarterly dividends, the holders of the preferred stock are entitled to elect a majority of RG&E's directors and their privilege continues until all dividends in default have been paid. The holders of preferred stock 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 RG&E's charter contains provisions to the effect that such holders shall be entitled to vote on certain matters affecting the rights and preferences of the preferred stock.

Whenever holders of preferred stock shall be entitled to vote, they shall be entitled to cast one vote for each share of preferred stock held by them. Holders of RG&E common stock are entitled to one vote per share on all matters.

Other long-term debt > At December 31, 2003 and 2002, the company's consolidated other long-term debt was:

			Amount	
	Maturity Dates	**Interest Rates**	**2003**	2002
(Thousands)				
First mortgage bonds (1)	2008 to 2033	5.84% to 10.06%	**$735,500**	$890,500
Pollution control notes – fixed	2006 to 2034	5 3/8% to 6.15%	**351,000**	351,000
Pollution control notes – variable	2015 to 2032	0.95% to 4.30%	**408,900**	408,900
Various long-term debt	2004 to 2033	1.20% to 10.48%	**2,173,355**	1,924,130
Putable asset term securities	–	–	**–**	300,000
Obligations under capital leases			**31,821**	34,447
Unamortized premium and discount on debt, net			**(31,161)**	(11,614)
			3,669,415	3,897,363
Less debt due within one year, included in current liabilities			**30,989**	545,404
Total			**$3,638,426**	$3,351,959

As a registered holding company under the Public Utility Holding Company Act of 1935, Energy East is prohibited from obtaining upstream guarantees and credit support from its subsidiaries. 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.

(1) For Energy East, on a consolidated basis, in addition to the information provided below for CMP, NYSEG and RG&E: Berkshire Gas and SCG have first mortgage bonds that are secured by liens on substantially all of their respective utility properties. CTG Resources and CNE have subsidiaries with long-term debt that is secured by properties of those subsidiaries.

CMP has no long-term debt obligations that are secured. CMP has no intercompany collateralizations and has no guarantees to affiliates or subsidiaries. CMP's debt has no guarantees from parent or affiliates or any additional credit supports.

NYSEG has no secured indebtedness. None of NYSEG's debt obligations are guaranteed or secured by any of its affiliates.

RG&E's first mortgage bonds, totaling $701 million at December 31, 2003, are secured by a first mortgage lien on substantially all of its properties. RG&E has no other secured indebtedness. None of RG&E's other debt obligations are guaranteed or secured by any of its affiliates.

At December 31, 2003, other long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years are:

2004	2005	2006	2007	2008
$30,989	$59,813	$340,377	$232,236	$93,303

Cross-Default Provisions > Energy East has a provision in its senior unsecured indenture, which provides that default by the company with respect to any other debt in excess of $40 million will be considered a default under the company's senior unsecured indenture.

NYSEG has provisions in its unsecured indenture and the reimbursement agreements relating to certain series of pollution control bonds, which provide that default by NYSEG with respect to any other debt in excess of $40 million in the case of the unsecured indenture and $5 million in the case of the reimbursement agreements will be considered a default under those respective documents.

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

NOTE [illegible] Bank Loans and Other Borrowings

The company and its subsidiaries have committed credit agreements with various expiration dates in 2004 and 2005 and pay fees in lieu of compensating balances in connection with these credit agreements. These agreements provided for maximum borrowings of $680 million at December 31, 2003, and $755 million at December 31, 2002. Uncommitted credit agreements, which expire in 2004, provide for additional borrowings of $16 million.

The company and its subsidiaries use short-term, unsecured notes and drawings on their credit agreements to finance certain refundings and for other corporate purposes. There was $308 million of such short-term debt outstanding at December 31, 2003, and $322 million outstanding at December 31, 2002. The weighted-average interest rate on short-term debt was 1.8% at December 31, 2003, and 2.1% at December 31, 2002.

In its revolving credit agreements Energy East covenants not to permit, without the consent of the lenders, its ratio of consolidated indebtedness to consolidated total capitalization at the last day of any fiscal quarter to exceed 0.65 to 1.00. Continued unremedied failure to comply with this covenant for 15 days after written notice of such failure from any lender constitutes an event of default and would result in acceleration of maturity. Energy East's ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit agreements was 0.57 to 1.00 at December 31, 2003.

In its revolving credit facility, secured by its accounts receivable, CMP covenants that (i) its consolidated total debt shall at all times be no more than 65% of the sum of its consolidated total debt and its total stockholder's equity, and (ii) as of the end of any fiscal quarter CMP's ratio of earnings before interest expense, income taxes and preferred stock dividends to interest expense shall have been at least 1.75 to 1.00. Continued unremedied failure to comply with either covenant for 30 days after such event has occurred constitutes an event of default and would result in acceleration of maturity. At December 31, 2003. CMP's consolidated total debt ratio was 31% and its interest coverage ratio was 4.0 to 1.00.

In their joint revolving credit agreement NYSEG and RG&E each covenant not to permit, without the consent of the lenders, (i) their respective ratio of earnings before interest expense and income tax to interest expense to be less than 1.5 to 1.0 at any time, and (ii) their respective ratio of total indebtedness to total capitalization to exceed 0.70 to 1.00 at any time. Continued unremedied failure to observe these covenants for five business days after written notice of such failure from any lender constitutes an event of default and would result in acceleration of maturity for the party in default. At December 31, 2003, the ratio of earnings before interest expense and income tax to interest expense was 5.2 to 1.0 for NYSEG and 1.9 to 1.0 for RG&E. At December 31, 2003, the ratio of total indebtedness to total capitalization was 0.53 to 1.00 for NYSEG and 0.50 to 1.00 for RG&E.

NYSEG has a letter of credit and reimbursement agreement in which it covenants not to permit, without the consent of the bank issuing the letter of credit, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 as of the last day of any fiscal quarter. Continued unremedied failure to comply with this covenant for 30 days after written notice of such failure from any lender constitutes an event of default and would result in acceleration of maturity. NYSEG's ratio of total indebtedness to total capitalization was 0.53 to 1.00 at December 31, 2003.

NOTE 9 Preferred Stock Redeemable Solely at the Option of Subsidiaries

At December 31, 2003 and 2002, the consolidated preferred stock was:

Subsidiary and Series	Par Value Per Share	Redemption Price Per Share	Shares Authorized and Outstanding(1)	Amount (Thousands) 2003	2002
CMP, 6% Noncallable	$100	–	5,180	**$518**	$518
CMP, 3.50%	100	$101.00	220,000	**22,000**	22,000
CMP, 4.60%	100	101.00	30,000	**3,000**	3,000
CMP, 4.75%	100	101.00	50,000	**5,000**	5,000
CMP, 5.25%	100	102.00	50,000	**5,000**	5,000
NYSEG, 3.75%	100	104.00	78,379	**7,838**	7,838
NYSEG, 4 1/2% (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
RG&E, 4% F	100	105.00	120,000	**12,000**	12,000
RG&E, 4.10% H	100	101.00	80,000	**8,000**	8,000
RG&E, 4.75% I	100	101.00	60,000	**6,000**	6,000
RG&E, 4.10% J	100	102.50	50,000	**5,000**	5,000
RG&E, 4.95% K	100	102.00	60,000	**6,000**	6,000
RG&E, 4.55% M	100	101.00	100,000	**10,000**	10,000
Berkshire, 4.80%	100	100.00	2,499	**250**	257
CNG, 6.00%	100	110.00	4,104	**411**	411
CNG, 8.00% Noncallable	3.125	–	108,706	**339**	340
Preferred stock issuance costs				**(2,582)**	(2,723)
Total				**$91,095**	$90,962

(1) At December 31, 2003, the company and its subsidiaries had 15,790,801 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 775,335 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.

The company's subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2001 through 2003:

Subsidiary	Date	Series	Amount
CNG	Various 2001	6.00%	$45,900 *
CNG	Various 2001	8.00%	$41,222 **
CNG	June 7, 2002	6.00%	$2,500 *
CNG	September 16, 2003	8.00%	$428 *
Berkshire	September 30, 2001	4.80%	$41,000 *
Berkshire	September 30, 2002	4.80%	$1,500 *
Berkshire	September 9, 2003	4.80%	$7,500 *

*Redeemed **Substantially all purchased at a premium

Voting rights > If preferred stock dividends on any series of preferred stock of a subsidiary, other than the 6% Noncallable series and the 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 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 6% Noncallable series and the 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 6% Noncallable series and the 8.00% series are entitled to one vote per share and have full voting rights on all matters.

Whenever holders of preferred stock shall be entitled to vote, they shall be entitled to cast one vote for each share of preferred stock held by them. Holders of NYSEG common stock are entitled to one vote per share on all matters, except in the election of directors with respect to which NYSEG common stock has cumulative voting rights. Holders of CMP common stock are entitled to one-tenth of one vote per share on all matters. Holders of the common stock of the other subsidiaries are entitled to one vote per share on all matters.

NOTE 10 Commitments

Capital spending > The company has commitments in connection with its capital spending program. Capital spending is projected to be $345 million in 2004, including nuclear fuel, and is expected to be paid for with internally generated funds. The program is subject to periodic review and revision. The company's capital spending will be primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates and merger integration.

Nonutility generator power purchase contracts > CMP and NYSEG together expensed approximately $608 million for NUG power in 2003, $611 million in 2002 and $593 million in 2001. CMP and NYSEG estimate that their combined NUG power purchases will be $642 million in 2004, $683 million in 2005, $609 million in 2006, $574 million in 2007 and $367 million in 2008.

NOTE 11 Jointly-Owned Generation Assets and Nuclear Generation Insurance and Decommissioning

Cayuga Energy, Inc. > Cayuga Energy owns an 85% interest in South Glens Falls Energy, LLC, the owner of a 67-megawatt natural gas-fired combined cycle generating station operating as an exempt wholesale generator.

As part of a joint venture with PEI Power Corporation, Cayuga Energy owns 50.1% of a 44-megawatt natural gas-fired peaking-power plant. The joint venture company, PEI Power II, LLC, operates the plant as an exempt wholesale generator.

CMP > CMP has ownership interests in three nuclear generating facilities in New England. The largest is a 38% interest in Maine Yankee Atomic Power Company. CMP also owns a 9.5% interest in Yankee Atomic Electric Company and a 6% interest in Connecticut Yankee Atomic Power Company. Maine Yankee, Yankee Atomic and Connecticut Yankee have been permanently shut down and are in the process of being decommissioned. CMP expects the decommissioning of Maine Yankee and Yankee Atomic to be completed in 2005 and the decommissioning of Connecticut Yankee to be completed in 2006.

In July 2002 Vermont Yankee Nuclear Power Corporation sold the Vermont Yankee nuclear power plant, including CMP's 4% ownership interest, to Entergy Corporation. Benefits realized by CMP from the sale, which were less than $1 million, were used to reduce CMP customers' future obligations for stranded costs. The transaction included a power purchase agreement that calls for Entergy to provide all of the plant's electricity to the sellers through 2012, the year the initial operating license for the plant expires.

Sale of Nine Mile Point 2 > In November 2001 NYSEG and RG&E sold their interests in NMP2 to Constellation Nuclear. In October 2001 the NYPSC issued an order approving the sale.

NYSEG: NYSEG's 18% share of NMP2's operating expenses until it was sold is included in various categories on the statements of income. Upon completion of the sale of NMP2, NYSEG recorded an asset sale gain of approximately $110 million, in accordance with the NYPSC's order approving the sale, as a regulatory liability under Statement 71. The gain includes a gross up for unfunded future income taxes and is being returned to customers in accordance with NYSEG's current electric rate plan, which was approved by the NYPSC in February 2002.

RG&E: For its 14% share of NMP2, the October 2001 NYPSC order provided for RG&E to establish a regulatory asset of approximately $326 million at the time of closing. RG&E agreed to a one-time $20 million pretax accelerated amortization of the regulatory asset that was recorded in the third quarter of 2001. In addition, RG&E accelerated its recognition of approximately $13 million of previously deferred investment tax credits. RG&E also agreed to amortize the regulatory asset by an additional $30 million per year during the period from the closing of the sale of NMP2 until RG&E's base electric rates are reset. The $30 million annual amortization reflects RG&E's projected savings for its share of NMP2 operating expenses compared to the estimated cost of electricity purchases to replace RG&E's presale share of the output. The terms associated with the recovery of the remaining regulatory asset will be established in future RG&E rate proceedings. The settlement further provides that it constitutes a final and irrevocable resolution of all RG&E ratemaking issues associated with the sale of NMP2 and RG&E's ability to recover through rates the costs associated with its investment in NMP2.

NYSEG and RG&E's pre-existing decommissioning funds for NMP2 were transferred to Constellation, which has taken responsibility for all future decommissioning funding.

The transaction included a power purchase agreement that calls for Constellation to provide electricity to NYSEG and RG&E, at fixed prices, for 10 years. The power purchase agreement is a contract for physical delivery of NYSEG's 18% share and RG&E's 14% share of 90% of the output from NMP2. NYSEG and RG&E record expenses for electricity purchased in accordance with the agreement at the time the power is physically delivered, at prices pursuant to the agreement. The contract is not required to be marked-to-market and is not considered to be a derivative instrument because it qualifies for the normal purchases and normal sales exception in Statement 133, as amended.

After the power purchase agreement is completed a revenue sharing agreement will begin. The revenue sharing agreement could provide additional revenue to NYSEG and RG&E through 2021, which would mitigate increases in electricity prices. Both agreements are based on plant output. No amounts are recorded under the revenue sharing agreement because any benefit that may occur between 2011 and 2021 cannot be estimated. Any benefits from the revenue sharing agreement will be deferred for customers.

Nuclear Insurance > The Price-Anderson Act is a federal statute providing, among other things, a limit on the maximum liability of nuclear reactor owners for damages resulting from a single nuclear incident. The public liability limit for a nuclear incident is approximately $10.9 billion and is subject to inflation and changes in the number of licensed reactors. RG&E carries the maximum available commercial insurance of $300 million and participates in the mandatory financial protection pool for the remaining $10.6 billion. Under the Price-Anderson Act, RG&E would be liable for up to $101 million per incident payable at a rate not to exceed $10 million per incident per year.

In addition to the insurance required by the Price-Anderson Act, RG&E also carries nuclear property damage insurance and accidental outage insurance through Nuclear Electric Insurance Limited. Under those insurance policies, RG&E could be subject to assessments if losses exceed the accumulated funds available to the insurers. The maximum amounts of the assessments for the current policy year are $13 million for nuclear property damage insurance and $4 million for accidental outage insurance.

Nuclear plant decommissioning costs > The present value of the estimated liability for decommissioning the various interests in nuclear plants, including spent fuel storage, is $134 million for CMP, which was updated in 2003 to include long-term spent fuel storage and increases in projected costs, and $421 million for RG&E. The amount currently billed or accrued for those costs is recovered by CMP and RG&E through their electric rates.

NOTE 12 Environmental Liability

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

The U.S. Environmental Protection Agency and various state environmental agencies, as appropriate, notified the company that it is among the potentially responsible parties who may be liable for costs incurred to remediate certain hazardous substances at 19 waste sites. The 19 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 19 sites, 10 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, one is included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and seven sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. The company has recorded an estimated liability of $2 million related to 13 of the 19 sites. Remediation costs have been paid at the remaining six sites, and the company expects no additional liability to be incurred. An estimated liability of $4 million has been recorded related to 12 sites where the company believes it is probable that it will incur remediation costs and/or monitoring costs, although it has not been notified that it is among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the estimated amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to the company.

The company has a program to investigate and perform necessary remediation at its 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 three of those four sites are part of Maine's Uncontrolled Sites Program, three sites are included in the Connecticut Inventory of Hazardous Waste Sites, and three sites are on the Massachusetts Department of Environmental Protection's list of confirmed disposal sites. The company has entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 39 of its 60 sites.

The company's estimate for all costs related to investigation and remediation of its 60 sites ranges from $138 million to $234 million at December 31, 2003. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $138 million at December 31, 2003, and $126 million at December 31, 2002. The company recorded a corresponding regulatory asset, net of insurance recoveries, since it expects to recover the net costs in rates.

Energy East's environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of Energy East's environmental liability accruals, which are expected to be paid through the year 2017, have been established on an undiscounted basis. Insurance settlements have been received by Energy East subsidiaries during the last three years, which they accounted for as reductions in their related regulatory assets.

NOTE 13 Fair Value of Financial Instruments

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

December 31	2003 Carrying Amount	2003 Estimated Fair Value	2002 Carrying Amount	2002 Estimated Fair Value
(Thousands)				
Investments – classified as available-for-sale	**$342,267**	**$342,217**	$296,425	$296,392
Debt owed to affiliate	**$355,670**	**$389,814**	–	–
Preferred stock of subsidiary subject to mandatory redemption requirements	**$25,000**	**$25,000**	–	–
First mortgage bonds	**$734,111**	**$810,677**	$888,870	$973,232
Pollution control notes – fixed	**$351,000**	**$367,385**	$351,000	$364,865
Pollution control notes – variable	**$408,900**	**$408,900**	$408,900	$408,900
Various long-term debt	**$2,143,583**	**$2,370,463**	$1,915,160	$2,088,303
Putable asset term securities	–	–	$298,986	$335,288

The carrying amounts for cash and cash equivalents, notes payable and interest accrued approximate their estimated fair values. Special deposits may include restricted funds set aside as collateral for first mortgage bonds and collateral received from counterparties. The carrying amount approximates fair value because the special deposits have been invested in securities that mature within one year. A majority of the investments classified as held for sale represents decommissioning trust funds for Ginna. In December 2003 those funds were converted to short-term, highly liquid investments in preparation for the sale of Ginna.

In 2001 the company evaluated the carrying value of its investment in NEON Communications, Inc. because there had been a significant decline in the market value of NEON common shares. That decline was consistent with the market performance of telecommunications businesses as a whole. A decline was determined to be other than temporary during the third quarter and the investment was written down to its fair market value of $12 million. That writedown totaled $46 million after taxes, or 39 cents per share.

During the first half of 2002 the company determined that additional declines in NEON's market value were other than temporary and further wrote down the cost basis of that investment. The investment was written down to $2 million based on the closing market price of NEON common shares on March 31, 2002. That writedown totaled $6 million after taxes, or 5 cents per share. In the second quarter of 2002 the NEON common shares were delisted from NASDAQ and NEON filed a reorganization plan under the U.S. Bankruptcy Code. The company wrote off its remaining $2 million investment during the second quarter, which was $1 million after taxes, or 1 cent per share.

The investment in NEON was classified as available-for-sale, accounted for by the cost method and carried at its fair value, with changes in fair value recognized in other comprehensive income. No income or loss related to the investment in NEON was included in the company's operating income in earlier periods.

NOTE 14 Stock-Based Compensation

The company applies Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, to account for its stock-based compensation plans. Compensation expense would have been the same in 2003, 2002 and 2001 had it been determined consistent with Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, because stock appreciation rights (SARs) were granted along with any options granted. SARs will continue to be issued along with any options granted.

The company may grant options and SARs to senior management and certain other key employees under its stock option plan. Options granted in 2001, 2002 and 2003 vest over either one-year or two-year periods, subject to, with certain exceptions, continuous employment. All options expire 10 years after the grant date. Of the 13 million shares authorized at December 31, 2003, and the 10 million shares authorized at December 31, 2002, unoptioned shares totaled 5.5 million at December 31, 2003, and 1.9 million at December 31, 2002.

The company recorded compensation expense (benefit) for options/SARs of $3 million in 2003, $12 million in 2002 and less than $(1) million in 2001.

During 2003, 639,500 options/SARs were granted with a weighted-average exercise price equal to the weighted-average fair value of $19.10. 3,000 options with a weighted-average exercise price of $18.55 and 882,970 SARs with a weighted-average exercise price of $18.67 were exercised in 2003. 763,355 options/SARs with an exercise price of $22.67 were forfeited in 2003. The 6,014,522 options/SARs outstanding at December 31, 2003, had a weighted-average exercise price of $20.87. Of those outstanding at December 31, 2003, 28,309 options/SARs with exercise prices ranging from $10.88 to $14.69 and a weighted-average remaining life of three years had a weighted-average exercise price of $10.89 and 5,986,213 options/SARs with exercise prices ranging from $17.94 to $28.72 and a weighted-average remaining life of seven years had a weighted-average exercise price of $20.92. Of those exercisable at December 31, 2003, 28,309 options/SARs with exercise prices ranging from $10.88 to $14.69 had a weighted-average price of $10.89 and 4,658,043 options/SARs with exercise prices ranging from $17.94 to $28.72 had a weighted-average exercise price of $21.17.

During 2002, 2,810,500 options/SARs were granted with a weighted-average exercise price equal to the weighted-average fair value of $20.34. 347,863 SARs with a weighted-average exercise price of $16.26 were exercised in 2002. 74,337 options/SARs with an exercise price of $19.43 were forfeited in 2002. The 7,024,347 options/SARs outstanding at December 31, 2002, had a weighted-average exercise price of $20.95. Of those outstanding at December 31, 2002, 91,309 options/SARs with exercise prices ranging from $10.88 to $14.69 and a weighted-average remaining life of four years had a weighted-average exercise price of $10.88 and 6,933,038 options/SARs with exercise prices ranging from $17.94 to $28.72 and a weighted-average remaining life of eight years had a weighted-average exercise price of $21.08. Of those exercisable at December 31, 2002, 91,309 options/SARs with exercise prices ranging from $10.88 to $14.69 had a weighted-average price of $10.88 and 4,611,209 options/SARs with exercise prices ranging from $17.94 to $28.72 had a weighted-average exercise price of $21.66.

During 2001, 1,799,000 options/SARs were granted with a weighted-average exercise price equal to the weighted-average fair value of $18.88. 54,332 SARs with a weighted-average exercise price of $17.51 were exercised in 2001. 34,000 options/SARs with an exercise price of $21.03 were forfeited in 2001. The 4,636,047 options/SARs outstanding at December 31, 2001, had a weighted-average exercise price of $20.95. Of those outstanding at December 31, 2001, 191,309 options/SARs with exercise prices ranging from $10.88 to $14.69 and a weighted-average remaining life of five years had a weighted-average exercise price of $10.88 and 4,444,738 options/SARs with exercise prices ranging from $17.94 to $28.72 and a weighted-average remaining life of eight years had a weighted-average exercise price of $21.38. Of those exercisable at December 31, 2001, 191,309 options/SARs with exercise prices ranging from $10.88 to $14.69 had a weighted-average price of $10.88 and 2,939,545 options/SARs with exercise prices ranging from $17.94 to $28.72 had a weighted-average exercise price of $22.17.

The company's Long-term Executive Incentive Share Plan provided participants cash awards if certain shareholder return criteria were achieved. There were no performance shares outstanding at December 31, 2003, and 59,130 performance shares outstanding at December 31, 2002. There was no compensation expense under this plan for 2003, $0.4 million for 2002 and no compensation expense for 2001. Beginning January 1, 2001, no new performance shares were granted under this plan (other than dividend performance shares). The plan was eliminated in 2003.

On February 13, 2003, the company awarded 229,230 shares of its common stock, issued out of its treasury stock, to certain employees under its Restricted Stock Plan and recorded deferred compensation of $4 million based on the market price of $19.20 per share of common stock on the date of the award. An aggregate two million shares may be granted under the Restricted Stock Plan, subject to adjustment. Shares of restricted stock are awarded 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 shares vest based on the conditions outlined in the restricted stock award grants, including the achievement of targeted shareholder returns, but no later than January 1, 2009.

NOTE 15 Accumulated Other Comprehensive Income

(Thousands)	Balance January 1 2001	2001 Change	Balance December 31 2001	2002 Change	Balance December 31 2002	2003 Change	Balance December 31 2003
Foreign currency translation adjustment, net of income tax benefit of $– for 2001, 2002 and 2003	$(86)	$86	–	–	–	–	–
Unrealized gains (losses) on investments:							
Unrealized holding gains (losses) during period, net of income tax benefit (expense) of $7,980 for 2001, $6,803 for 2002 and $(253) for 2003		(10,400)		$(9,654)		$744	
Reclassification adjustment for losses included in net income, net of income tax benefit of $32,674 for 2001 and $5,087 for 2002		45,748		7,122		–	
Net unrealized gains (losses) on investments	(34,107)	35,348	$1,241	(2,532)	$(1,291)	744	$(547)
Minimum pension liability adjustment, net of income tax benefit (expense) of $1,828 for 2001, $39,378 for 2002 and $(14,484) for 2003	(630)	(2,546)	(3,176)	(58,485)	(61,661)	21,192	(40,469)
Unrealized gains (losses) on derivatives qualified as hedges:							
Unrealized gains on derivatives qualified as hedges arising during the period due to cumulative effect of a change in accounting principle, net of income tax expense of $(38,671) for 2001		58,250		–		–	
Unrealized gains (losses) during period on derivatives qualified as hedges, net of income tax benefit (expense) of $59,510 for 2001, $(26,984) for 2002 and $(14,391) for 2003		(89,955)		37,692		22,320	
Reclassification adjustment for (gains) losses included in net income, net of income tax (benefit) expense of $(7,416) for 2001, $(7,351) for 2002 and $14,123 for 2003		11,305		11,493		(21,303)	
Net unrealized gains (losses) on derivatives qualified as hedges	–	(20,400)	(20,400)	49,185	28,785	1,017	29,802
Accumulated Other Comprehensive Income (Loss)	$(34,823)	$12,488	$(22,335)	$(11,832)	$(34,167)	$22,953	$(11,214)

(See Risk management in Note 1.)

NOTE 18 Retirement Benefits

(Thousands)	Pension Benefits 2003	Pension Benefits 2002	Postretirement Benefits 2003	Postretirement Benefits 2002
Change in benefit obligation				
Benefit obligation at January 1	**$2,093,864**	$1,369,448	**$557,270**	$408,427
Service cost	**31,216**	29,318	**6,686**	6,040
Interest cost	**132,491**	111,943	**36,712**	32,215
Plan participants' contributions	**–**	–	**303**	212
Plan amendments	**9**	465	**(785)**	(11,922)
Actuarial loss	**62,881**	114,742	**44,371**	55,240
Business combination	**–**	501,454	**–**	92,198
Curtailment	**(655)**	–	**–**	–
Special termination benefits	**–**	64,909	**–**	–
Benefits paid	**(179,687)**	(98,415)	**(33,321)**	(25,140)
Benefit obligation at December 31	**$2,140,119**	$2,093,864	**$611,236**	$557,270
Change in plan assets				
Fair value of plan assets at January 1	**$2,064,401**	$1,822,052	**$34,088**	$38,634
Actual return on plan assets	**487,346**	(244,955)	**5,905**	(3,248)
Employer contributions	**20,006**	329	**30,044**	23,215
Plan participants' contributions	**–**	–	**303**	212
Business combination	**–**	585,390	**–**	–
Adjustment	**–**	–	**–**	415
Benefits paid	**(179,687)**	(98,415)	**(33,321)**	(25,140)
Fair value of plan assets at December 31	**$2,392,066**	$2,064,401	**$37,019**	$34,088
Funded status	**$251,947**	$(29,463)	**$(574,217)**	$(523,182)
Unrecognized net actuarial loss	**312,856**	527,617	**140,940**	106,401
Unrecognized prior service cost (benefit)	**45,360**	50,741	**(48,221)**	(54,929)
Unrecognized net transition (asset) obligation	**(1,230)**	(8,469)	**72,595**	80,661
Prepaid (accrued) benefit cost	**$608,933**	$540,426	**$(408,903)**	$(391,049)
Amounts recognized on the balance sheet				
Prepaid benefit cost	**$608,933**	$540,426	**–**	$99
Accrued benefit cost	**–**	–	**$(408,903)**	(391,148)
Additional minimum liability	**(149,101)**	(185,321)	**–**	–
Intangible asset	**5,847**	6,226	**–**	–
Regulatory liability	**76,914**	76,913	**–**	–
Accumulated other comprehensive income	**66,340**	102,182	**–**	–
Net amount recognized	**$608,933**	$540,426	**$(408,903)**	$(391,049)

The company uses a December 31 measurement date for its pension and postretirement benefit plans.

The company's accumulated benefit obligation for all defined benefit pension plans was $1.9 billion at December 31, 2003 and 2002.

CMP Group's, CNE's and CTG Resources' postretirement benefits were partially funded as of December 31, 2003 and 2002.

The minimum liability included in other comprehensive income for pension benefits decreased $36 million in 2003 and increased $98 million in 2002. The company recorded a minimum pension liability of $149 million at December 31, 2003, as required by Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions. The effect of the minimum pension liability was recognized in other long-term liabilities, intangible assets, regulatory liability and other comprehensive income, as appropriate, and is prescribed when the accumulated benefit obligation in the plan exceeds the fair value of the underlying pension plan assets and accrued pension liabilities. The decrease in the unfunded accumulated benefit obligation in 2003 was primarily due to a higher than estimated actual return on plan assets.

Weighted-average assumptions used to determine benefit obligations at December 31	Pension Benefits		Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rate	**6.25%**	6.50%	**6.25%**	6.50%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

As of December 31, 2003, the company decreased its discount rate from 6.5% to 6.25%.

	Pension Benefits			Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
(Thousands)						
Components of net periodic benefit cost						
Service cost	**$31,216**	$29,318	$23,967	**$6,686**	$6,040	$5,091
Interest cost	**132,491**	111,943	90,949	**36,712**	32,215	25,024
Expected return on plan assets	**(204,173)**	(190,541)	(161,731)	**(2,801)**	(2,993)	(3,378)
Amortization of prior service cost	**4,985**	8,035	7,822	**(6,879)**	(6,761)	(6,753)
Recognized net actuarial gain	**(6,185)**	(36,686)	(41,750)	**6,729**	1,647	(4,122)
Amortization of transition (asset) obligation	**(7,238)**	(7,238)	(7,238)	**8,066**	9,126	9,126
Special termination benefits	**–**	64,909	2,551	**–**	–	–
Curtailment	**403**	–	–	**(614)**	–	–
Deferral for future recovery	**–**	(32,086)	–	**–**	–	–
Net periodic benefit cost	**$(48,501)**	$(52,346)	$(85,430)	**$47,899**	$39,274	$24,988

Net periodic benefit cost is included in other operating expenses. The net periodic benefit cost for postretirement benefits represents the cost the company charged to expense for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred was $80 million as of December 31, 2003, and $88 million as of December 31, 2002. The company expects to recover any deferred postretirement costs by 2012. The transition obligation for postretirement benefits is being amortized over a period of 20 years.

Weighted-average assumptions used to determine net periodic benefit cost Year ended December 31	Pension Benefits			Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.50%**	7.00%	7.25%	**6.50%**	7.00%	7.25%
Expected return on plan assets	**8.75%**	9.00%	9.00%	**8.75%**	9.00%	9.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

The company's expected rate of return on plan assets assumption was developed based on a review of historical returns for the major asset classes. This analysis also considered both current capital market conditions and projected future conditions. Given the current low interest rate environment, the company selected an assumption of 8.75% per year, which is lower than the rate otherwise determined solely based on historical returns.

The company assumed a 10.0% annual rate of increase in the per capita cost of covered health care benefits for 2004 that gradually decreases to 5.0% by the year 2007. 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
Effect on total of service and interest cost components	$2 million	$(2 million)
Effect on postretirement benefit obligation	$35 million	$(30 million)

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduces a federal subsidy to sponsors of retiree health care benefit plans that provides a benefit that is at least actuarially equivalent to Medicare Part D.

In accordance with FASB Staff Position No. FAS 106-1, any measures of the accumulated pension benefit obligation or net periodic postretirement benefit cost in the company's financial statements or accompanying notes do not reflect the effects of the Act on its plans. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require a sponsor to change previously reported information. Moreover, the issues of how and when the federal subsidy should be accounted for are not yet resolved by the FASB. The company has not yet determined the potential effects of the Act on its future postretirement costs, including the participation rates in its benefit plans, nor whether any amendments to its benefit plans are appropriate given the provisions of the Act.

The company's weighted-average asset allocations at December 31, 2003 and 2002, by asset category are:

	Pension Benefits			Postretirement Benefits		
Asset Category	**Target Allocation**	**2003**	2002	**Target Allocation**	**2003**	2002
Equity securities	60%	**64%**	59%	50%	**53%**	49%
Debt securities	30%	**34%**	41%	45%	**45%**	48%
Real estate	5%	–	–	–	–	–
Other	5%	**2%**	–	5%	**2%**	3%
Total	100%	**100%**	100%	100%	**100%**	100%

The company's pension plan assets are held in a master trust with a trustee and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with the company's risk tolerance. This is achieved through the utilization of multiple asset managers and systematic allocation to investment management styles, providing a broad exposure to different segments of the fixed income and equity markets.

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

Equity securities included no Energy East common stock as of December 31, 2003 and 2002.

As of December 31, 2003 and 2002, the accumulated benefit obligation and the projected benefit obligation exceeded the fair value of pension plan assets for CMP's, CNG's and SCG's plans. As of December 31, 2002, the projected benefit obligation exceeded the fair value of pension plan assets for RG&E's plan. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those four companies' plans.

	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
December 31	**2003**	2002	**2003**	2002
(Thousands)				
Projected benefit obligation	**$478,899**	$1,008,967	**$478,899**	$455,666
Accumulated benefit obligation	**$430,754**	$901,229	**$430,754**	$408,131
Fair value of plan assets	**$365,431**	$825,134	**$365,431**	$298,810

The company expects to contribute between $7 million and $12 million to its pension plans and $10 million to its other postretirement benefit plans in 2004.

Expected benefit payments, which reflect expected future service, as appropriate, are as follows:

(Thousands)	Pension Benefits	Postretirement Benefits
2004	$132,127	$45,614
2005	$135,585	$48,932
2006	$141,743	$52,323
2007	$147,573	$55,605
2008	$157,399	$57,853
2009 - 2013	$987,632	$333,322

NOTE 17 Segment Information

Selected financial information for the company's business segments is presented in the table below. The company's electric delivery segment consists of its regulated transmission, distribution and generation operations in New York and Maine and its natural gas delivery segment consists of its regulated transportation, storage and distribution operations in New York, Connecticut, Maine and Massachusetts. Other includes: the company's corporate assets, interest income, interest expense and operating expenses; intersegment eliminations; and nonutility businesses.

(Thousands)	Electric Delivery	Natural Gas Delivery	Other	Total
2003				
Operating Revenues	**$2,758,695**	**$1,462,127**	**$372,997**	**$4,593,819**
Depreciation and Amortization	**$211,120**	**$81,433**	**$8,711**	**$301,264**
Operating Income	**$446,894**	**$198,945**	**$4,275**	**$650,114**
Interest Charges, Net	**$201,684**	**$76,113**	**$7,005**	**$284,802**
Income Taxes	**$89,337**	**$50,096**	**$(11,746)**	**$127,687**
Discontinued Operations	**-**	**-**	**$3,059**	**$3,059**
Net Income	**$152,720**	**$70,837**	**$(13,111)**	**$210,446**
Total Assets	**$7,293,829**	**$3,536,280**	**$476,323**	**$11,306,432**
Capital Spending	**$192,409**	**$99,746**	**$10,357**	**$302,512**
2002				
Operating Revenues	$2,568,247	$1,032,539	$235,683	$3,836,469
Depreciation and Amortization	$162,515	$71,329	$8,267	$242,111
Operating Income	$449,029	$149,656	$(5,890)	$592,795
Interest Charges, Net	$183,716	$73,177	$(601)	$256,292
Income Taxes	$94,238	$26,557	$(21,957)	$98,838
Discontinued Operations	–	–	$(1,913)	$(1,913)
Net Income	$170,337	$51,128	$(32,862)	$188,603
Total Assets	$7,032,043	$3,428,956	$483,348	$10,944,347
Capital Spending	$137,414	$86,301	$5,672	$229,387
2001				
Operating Revenues	$2,504,896	$1,026,124	$218,823	$3,749,843
Depreciation and Amortization	$118,882	$75,432	$8,996	$203,310
Operating Income	$553,421	$89,518	$(5,069)	$637,870
Interest Charges, Net	$154,011	$55,785	$6,592	$216,388
Income Taxes	$178,125	$18,144	$(41,390)	$154,879
Discontinued Operations	–	–	$(1,105)	$(1,105)
Net Income	$228,782	$17,938	$(59,113)	$187,607
Total Assets	$4,175,280	$2,467,647	$626,305	$7,269,232
Capital Spending	$95,627	$106,116	$21,132	$222,875

NOTE 18 Quarterly Financial Information (Unaudited)

Quarter Ended (Thousands, except per share amounts)	March 31	June 30	September 30	December 31
2003				
Operating Revenues	**$1,508,295**	**$986,082**	**$903,124**	**$1,196,318**
Operating Income	**$291,922**	**$124,951**	**$72,229**	**$161,012**
Income from Continuing Operations	**$130,509**	**$28,852**	**$2,083**	**$45,943**
Net Income (Loss)	**$135,464**	**$27,717**	**$(5,979)**	**$53,244**
Earnings (Loss) Per Share, basic	**$.93**	**$.19**	**$(.04)**	**$.37**
Earnings (Loss) Per Share, diluted	**$.93**	**$.19**	**$(.04)**	**$.36**
Dividends Per Share	**$.25**	**$.25**	**$.25**	**$.25**
Average Common Shares Outstanding, basic	**145,096**	**145,415**	**145,684**	**145,936**
Average Common Shares Outstanding, diluted	**145,215**	**145,640**	**145,901**	**146,150**
Common Stock Price[1]				
High	**$23.71**	**$21.95**	**$22.48**	**$23.71**
Low	**$17.40**	**$17.70**	**$19.39**	**$21.64**
2002				
Operating Revenues	$1,025,426	$713,114	$939,308	$1,158,621
Operating Income	$238,823	$81,971	$119,074	$152,927
Income from Continuing Operations	$105,614	$5,679	$27,531	$51,692
Net Income	$105,570[2]	$5,323[2]	$23,742	$53,968[3]
Earnings Per Share, basic and diluted	$.90[2]	$.05[2]	$.16	$.37[3]
Dividends Per Share	$.24	$.24	$.24	$.24
Average Common Shares Outstanding, basic and diluted	116,720	117,820	144,621	144,849
Common Stock Price[1]				
High	$21.92	$23.13	$22.53	$22.70
Low	$18.50	$20.92	$15.75	$18.25

(1) The company's common stock is listed on the New York Stock Exchange. The number of shareholders of record was 37,674 at December 31, 2003.

(2) Includes the effect of writedowns of the company's investment in NEON Communications, Inc. in 2002 that decreased net income and earnings per share as follows: $6 million and 5 cents in the first quarter and $1 million and 1 cent in the second quarter.

(3) Includes the effect of restructuring expenses recorded in the fourth quarter of 2002 that decreased net income $24 million and earnings per share 17 cents.

The company's management is responsible for the preparation, integrity and reliability of the consolidated financial statements, notes and other information in this annual report. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles and include estimates that are based upon management's judgment and the best available information. Other financial information contained in this report was prepared on a basis consistent with that of the consolidated financial statements.

The company maintains a system of internal controls over financial reporting designed to provide reasonable assurance to its management and board of directors regarding the preparation of reliable published financial statements and the safeguarding of assets against loss or unauthorized use. The system contains self-monitoring mechanisms and actions are taken to correct deficiencies as they are identified. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of the circumvention or overriding of controls, and therefore can provide only reasonable assurance with respect to financial statement preparation and the safeguarding of assets. Further, because of changes in conditions, internal control system effectiveness may vary over time.

The company maintains an internal audit department that independently assesses the effectiveness of the internal controls over financial reporting. In addition, the company's independent auditors, PricewaterhouseCoopers LLP, have considered the company's internal control structure to the extent they considered necessary in expressing an opinion on the consolidated financial statements. Management is responsive to the recommendations of its internal audit department and the independent auditors concerning internal controls over financial reporting and corrective measures are taken when considered appropriate. In addition, a Code of Conduct addresses areas of compliance and provides employees, officers and the board of directors with guidance that promotes sound ethical business practices. It also requires all management employees to formally affirm their compliance with the Code of Conduct. The board of directors oversees the company's financial reporting through its audit committee. The committee, which consists entirely of independent directors, meets regularly with management, the internal auditor and the independent auditors to discuss auditing, internal control and financial reporting matters, and assists the board of directors in overseeing the company's Corporate Compliance Program. Both the internal auditor and independent auditors have direct access to the audit committee, independent of management.

Robert E. Rude
Vice President and Controller

Kenneth M. Jasinski
Executive Vice President and Chief Financial Officer

Wesley W. von Schack
Chairman, President & Chief Executive Officer

PRICEWATERHOUSECOOPERS

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

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 ("the Company") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion.

As discussed in Notes 1 and 15 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative and hedging activities pursuant to Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by Statement of Financial Accounting Standards No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities (an amendment of FASB Statement No. 133). As discussed in Notes 1 and 5 to the consolidated financial statements, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets. As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, and effective July 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. In addition, as discussed in Note 1 to the consolidated financial statements, effective December 31, 2003, the Company changed its method of accounting for its capital trust subsidiary in accordance with Financial Accounting Standards Board Interpretation No. 46R, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51.

PricewaterhouseCoopers LLP

New York, New York
January 30, 2004

	2003	2002[3]	2001	2000[8]	1999
(Thousands, except per share amounts)					
Operating Revenues					
Sales and services	**$4,593,819**	$3,836,469	$3,749,843	$2,955,661	$2,278,608
Operating Expenses					
Electricity purchased and fuel used in generation	**1,329,443**	1,276,087	1,334,507	1,073,728	905,367
Natural gas purchased	**1,001,649**	603,258	694,038	496,509	186,722
Other operating expenses	**837,953**	691,987	560,572	432,373	312,129
Maintenance	**202,918**	160,230	139,321	108,074	85,849
Depreciation and amortization	**301,264**	242,111	203,310	165,216	648,970[9]
Other taxes	**270,478**	229,434	192,505	165,674	179,028
Restructuring expenses	**–**	40,567	–	–	–
Gain on sale of generation assets	**–**	–	(84,083)	–	(674,572)
Deferral of asset sale gain	**–**	–	71,803	–	–
Writeoff of Nine Mile Point 2	**–**	–	–	–	72,532
Total Operating Expenses	**3,943,705**	3,243,674	3,111,973	2,441,574	1,716,025
Operating Income	**650,114**	592,795	637,870	514,087	562,583
Writedown of Investment	**–**	12,209	78,422[5]	–	–
Other (Income) and Deductions	**11,229**	2,811	(14,986)	(30,392)	(12,573)
Interest Charges, Net	**284,802**	256,292	216,388	152,520	132,908
Preferred Stock Dividends of Subsidiaries	**19,009**	32,129	14,455	963	2,706
Income From Continuing Operations Before Income Taxes	**335,074**	289,354	343,591	390,996	439,542
Income Taxes	**127,687**	98,838	154,879	155,684	220,791
Income From Continuing Operations	**207,387**	190,516	188,712	235,312	218,751
Discontinued Operations					
Loss from businesses sold (including loss on disposal in 2003 of $13,360)	**(9,953)**	(2,227)	(1,605)	(401)	–
Income taxes (benefits)	**(13,012)**	(314)	(500)	(123)	–
Income (Loss) From Discontinued Operations	**3,059**	(1,913)	(1,105)	(278)	–
Net Income	**210,446**	188,603[4]	187,607[5][6]	235,034[6]	218,751
Common Stock Dividends	**145,417**	125,456	107,342	99,606	98,725
Retained Earnings Increase	**$65,029**	$63,147	$80,265	$135,428	$120,026
Average Common Shares Outstanding, basic	**145,535**	131,117	116,708	114,213	116,316
Earnings Per Share from Continuing Operations, basic[1]	**$1.43**	$1.45[4]	$1.62[5]	$2.06	$1.88
Earnings Per Share, basic[2]	**$1.45**	$1.44[4]	$1.61[5]	$2.06	$1.88
Dividends Paid Per Share	**$1.00**	$.96	$.92	$.88	$.84
Book Value Per Share of Common Stock at Year End	**$17.59**	$16.97	$15.26	$14.59	$12.84
Capital Spending	**$302,512**	$229,387	$222,875	$168,320	$82,674
Total Assets	**$11,306,432**	$10,944,347	$7,269,232[7]	$7,013,728[7]	$3,773,171[7]
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	**$4,017,846**	$3,721,959	$2,816,278	$2,346,814	$1,235,089

Reclassifications: Certain amounts included in Selected Financial Data have been reclassified to conform to the 2003 presentation.
(1) Earnings per share from continuing operations, diluted for 2003 is $1.42, and for all other years is the same as basic.
(2) Earnings per share, diluted for 2003 is $1.44, and for all other years is the same as basic.
(3) Due to the completion of the company's merger transaction during 2002 the consolidated financial statements include RGS Energy's results beginning with July 2002.
(4) Includes the writedown of the company's investment in NEON Communications, Inc. that decreased net income $7 million and earnings per share 6 cents and the effect of restructuring expenses that decreased net income $24 million and earnings per share 19 cents.
(5) Includes the writedown of the company's investment in NEON Communications, Inc. that decreased net income $46 million and earnings per share 39 cents.
(6) Includes goodwill amortization of $25 million in 2001 and $18 million in 2000.
(7) Does not reflect the reclassification of accrued removal costs from accumulated depreciation to a regulatory liability.
(8) Due to the completion of the company's merger transactions during 2000 the consolidated financial statements include CNE's results beginning with February 2000 and include CMP Group's, CTG Resources' and Berkshire Energy Resources' results beginning with September 2000.
(9) Depreciation and amortization includes accelerated amortization of NMP2 related to the sale of the company's coal-fired generation assets, authorized by the NYPSC.

(Thousands)	2003	2002	2001	2000	1999
Electric Deliveries					
(Megawatt-hours)					
Residential	**11,676**	10,226	8,594	6,473	5,447
Commercial	**9,266**	8,019	6,527	4,504	3,517
Industrial	**7,412**	6,694	6,525	4,613	3,383
Other	**2,239**	1,930	1,592	1,543	1,496
Total Retail	**30,593**	26,869	23,238	17,133	13,843
Wholesale	**5,734**	5,330	6,048	6,214	10,978
Total Electric Deliveries	**36,327**	32,199	29,286	23,347	24,821
Electric Revenues					
Residential	**$1,204,228**	$1,073,586	$998,846	$820,093	$747,964
Commercial	**667,802**	609,165	622,996	460,453	393,623
Industrial	**344,352**	313,622	314,527	263,633	237,637
Other	**191,756**	175,130	162,987	153,283	159,730
Total Retail	**2,408,138**	2,171,503	2,099,356	1,697,462	1,538,954
Wholesale	**233,331**	190,090	238,094	212,630	312,727
Other	**117,226**	206,654	167,446	113,518	37,637
Total Electric Revenues	**$2,758,695**	$2,568,247	$2,504,896	$2,023,610	$1,889,318
Natural Gas Deliveries					
(Dekatherms)					
Residential	**85,401**	62,748	52,846	42,238	23,327
Commercial	**25,938**	21,190	20,699	15,823	8,247
Industrial	**3,458**	2,934	2,847	2,690	1,669
Other	**11,301**	14,507	12,726	10,074	2,677
Transportation of customer-owned natural gas	**86,647**	80,480	58,882	37,314	23,426
Total Retail	**212,745**	181,859	148,000	108,139	59,346
Wholesale	**5,360**	7,074	9,298	10,674	8,617
Total Natural Gas Deliveries	**218,105**	188,933	157,298	118,813	67,963
Natural Gas Revenues					
Residential	**$944,010**	$594,279	$576,115	$390,794	$181,579
Commercial	**266,409**	192,023	226,215	145,318	63,112
Industrial	**27,312**	20,883	26,220	19,339	8,123
Other	**86,162**	83,735	89,524	68,652	14,745
Transportation of customer-owned natural gas	**99,896**	84,927	73,213	59,901	33,572
Total Retail	**1,423,789**	975,847	991,287	684,004	301,131
Wholesale	**21,070**	17,260	37,748	55,184	21,831
Other	**17,268**	39,432	(2,911)	32,943	8,783
Total Natural Gas Revenues	**$1,462,127**	$1,032,539	$1,026,124	$772,131	$331,745

Board of Directors

Richard Aurelio, a director since 1997, formerly President of Time Warner Cable Group New York and NY One News, is now a director of the Javits Foundation, all in New York, New York, and Communications Dispute Resolutions, LLC, in Miami, Florida.

James A. Carrigg, a director since 1983, is a director of Security Mutual Life Insurance Company of New York and National Security Life and Annuity Company, both in Binghamton, New York.

Joseph J. Castiglia, a director since 1995, is Chairman of HealthNow New York, Inc., DBA Blue Cross & Blue Shield of Western New York, in Buffalo, New York, and Blue Shield of Northeastern New York, in Albany, New York.

Lois B. DeFleur, a director since 1995, is President of the State University of New York at Binghamton in Binghamton, New York.

G. Jean Howard, a director since 2002, is Executive Director of Wilson Commencement Park in Rochester, New York.

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

John M. Keeler, a director since 1989, is counsel at Hinman, Howard & Kattell, LLP, attorneys-at-law in Binghamton, New York.

Ben E. Lynch, a director since 1987, is President of Winchester Optical Company in Elmira, New York.

Peter J. Moynihan, a director since 2000, is a former 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, DeFleur, Jagger

Compensation and Management Succession: Castiglia, Aurelio, Lynch

Corporate Responsibility: Carrigg, Howard, Keeler, Moynihan, Rich

Nominating and Corporate Governance: Aurelio, DeFleur, Rich

Energy East Officers

Robert M. Allessio
President – The Berkshire Gas Company

Richard R. Benson
Vice President – Human Resources

Sara J. Burns
President – Central Maine Power Company

Michael I. German
President – Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company

Kenneth M. Jasinski
Executive Vice President and Chief Financial Officer

Robert D. Kump
Vice President, Treasurer & Secretary

James P. Laurito
President – New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation

F. Michael McClain
Vice President – Finance and Chief Integration Officer

Patrick T. Neville
Vice President – Information Technology

Clifton B. Olson
Vice President – Energy Supply

Jessica S. Raines
Vice President – Supply Chain

Robert E. Rude
Vice President and Controller

Angela M. Sparks-Beddoe
Vice President – Public Affairs

Carl A. Taylor
President – The Energy Network, Inc.

Denis E. Wickham
Executive Vice President and Chief Operating Officer – New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation

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

Mellon Internet Address:

www.melloninvestor.com

Mellon's Internet Web site provides shareholders access to Investor Service Direct (ISD). Through ISD, shareholders can view their account profiles, stock certificate histories, dividend reinvestment transactions, current stock price quote and historical stock closing prices. Shareholders may also request a replacement dividend check, the issuance of stock certificates or the sale of shares from their Investor Services Program account.

Shareholders may also contact Mellon by telephone. 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) at 1-800-542-7480.

Shareholders may obtain a free copy of 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 Manager, Investor Relations by telephone at 207-688-4336 or by fax at 207-688-4354.

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 Web site.

trading symbol: EAS

Connecticut

Connecticut Natural Gas Corporation delivers natural gas to 153,000 customers in central Connecticut.

The Southern Connecticut Gas Company delivers natural gas to 171,000 customers in southern Connecticut.

Maine

Central Maine Power Company delivers electricity to 572,000 customers in central and southern Maine.

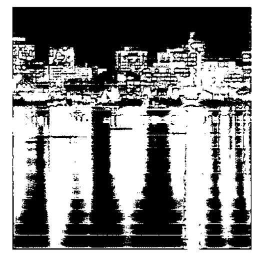
Massachusetts

The Berkshire Gas Company delivers natural gas to 35,000 customers in western Massachusetts.

New York

New York State Electric & Gas Corporation delivers electricity to 848,000 customers and natural gas to 253,000 customers across more than 40% of upstate New York.

Rochester Gas and Electric Corporation delivers electricity to 356,000 customers and natural gas to 292,000 customers in a nine-county region centered around the city of Rochester.



essential

utilities at-a-glance

	Berkshire Gas	CMP	CNG	NYSEG	RG&E	SCG
State	Massachusetts	Maine	Connecticut	New York	New York	Connecticut
Electricity customers		572,000		848,000	356,000	
Natural gas customers	35,000		153,000	253,000	292,000	171,000
Electricity delivered (gwh)		11,326		16,137	8,864	
Natural gas delivered (000 dth)	7,738		35,350	66,323	55,207	30,060
Electricity revenue ($ million)		611		1,471	677	
Natural gas revenue ($ million)	62		332	405	348	308
Assets ($ million)	222	1,807	753	3,588	2,961	953

Utility Companies

Central Maine Power Company (CMP)
83 Edison Drive
Augusta, ME 04336
www.cmpco.com

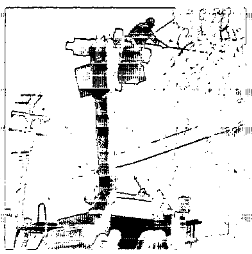
Connecticut Natural Gas Corporation (CNG)
77 Hartland Street
4th Floor
East Hartford, CT 06108
www.cngcorp.com

New York State Electric & Gas Corporation (NYSEG)
Carrigg Center –
Corporate Drive
P.O. Box 5224
Binghamton, NY 13902-5224
www.nyseg.com

Rochester Gas and Electric Corporation (RG&E)
89 East Avenue
Rochester, NY 14649
www.rge.com

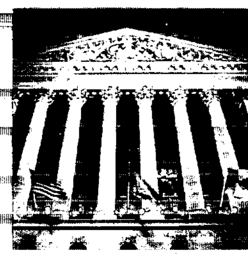
The Berkshire Gas Company (Berkshire Gas)
115 Cheshire Road
Pittsfield, MA 01201
www.berkshiregas.com

The Southern Connecticut Gas Company (SCG)
855 Main Street
Bridgeport, CT 06604
www.soconngas.com


reliable


efficient


streamlined


ethical

"As we look to 2004 you can expect our initiatives to continue to support our focused energy distribution strategy."

EnergyEast

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