RG&E
Always at Your Service

**Robert C. Mecredy**
Vice President
Nuclear Operations

April 7, 2003

Mr. Robert L. Clark
Office of Nuclear Regulatory Regulation
U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Subject: Annual Corporate Financial Report
R.E. Ginna Nuclear Power Plant
Docket No. 50-244

Dear Mr. Clark:

Pursuant to 10 CFR 50.71(b), Rochester Gas and Electric Corporation (RG&E) submits the attached Energy East Corporation Annual Report for 2002.

Very truly yours,

Robert C. Mecredy

1000704

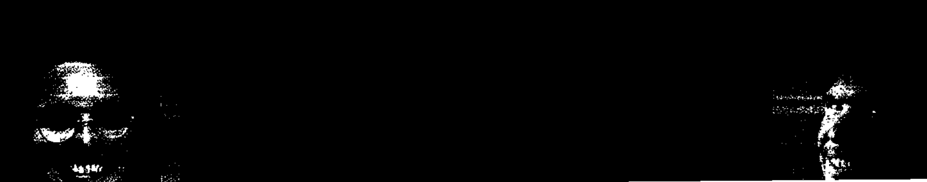
M004

# Energy East Corporation Annual Report 2002

# 2002

A year of **analysis** and **integration**

We have redefined how we run our business >



FEBRUARY 18, 2003

Dear Shareholders:

Most equity investors will look back on 2002 as another disappointing year. Difficult economic conditions were aggravated by a crisis in investor confidence brought about by corporate scandals and malfeasance. The utility industry contributed to this "confidence crisis" as strategic choices made by a number of utilities to turbo-charge growth beyond that available in their regulated business simply did not work out.

Despite this market turmoil, Energy East common stock returned 16% in 2002, outperforming the Standard & Poor's Utility Index, which lost 33%, and the Standard & Poor's 500, which lost 23%. In addition, in January we increased our common stock dividend for the sixth consecutive year. Over that time period, Energy East's dividend has increased by more than 40%. We have been able to achieve steady cash flows, solid earnings and consistent dividend growth by staying focused on our core business – a super regional, "pipes and wires" energy delivery company. Energy East has not invested in speculative generation plants, nor do we have any trading or international businesses. Energy East derives predominantly all of its earnings, and cash flow, from conservatively managed, regulated, retail energy delivery businesses. I firmly believe that there is a niche in every investor's portfolio for companies that have strategies such as ours.



Last year, we set the following objectives for 2002:

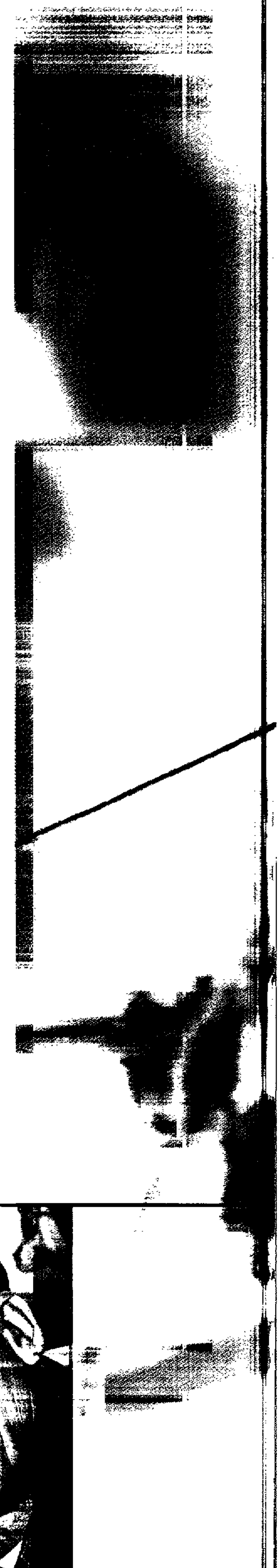
> Complete our merger with RGS Energy

> Implement long-term incentive-based rate plans for NYSEG's natural gas business, as well as the electric and natural gas businesses of Rochester Gas and Electric (RG&E), the primary subsidiary of RGS Energy;

> Further integrate the five electric and natural gas utilities that we acquired since 2000; and

> Continue to provide our customers with a reliable, essential, energy infrastructure, their choice of commodity supplier, stable delivery prices, and excellent customer service.

I am proud to say that through the hard work of the entire Energy East team, we accomplished nearly all of these objectives.



# essential

I make sure the energy delivery infrastructure — **our pipes and wires** — remains reliable.

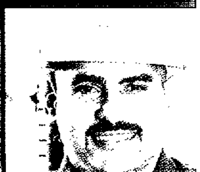
**CMP** Maine is the most tree-covered state in the nation. However, CMP customers enjoy 99.9 percent reliability.

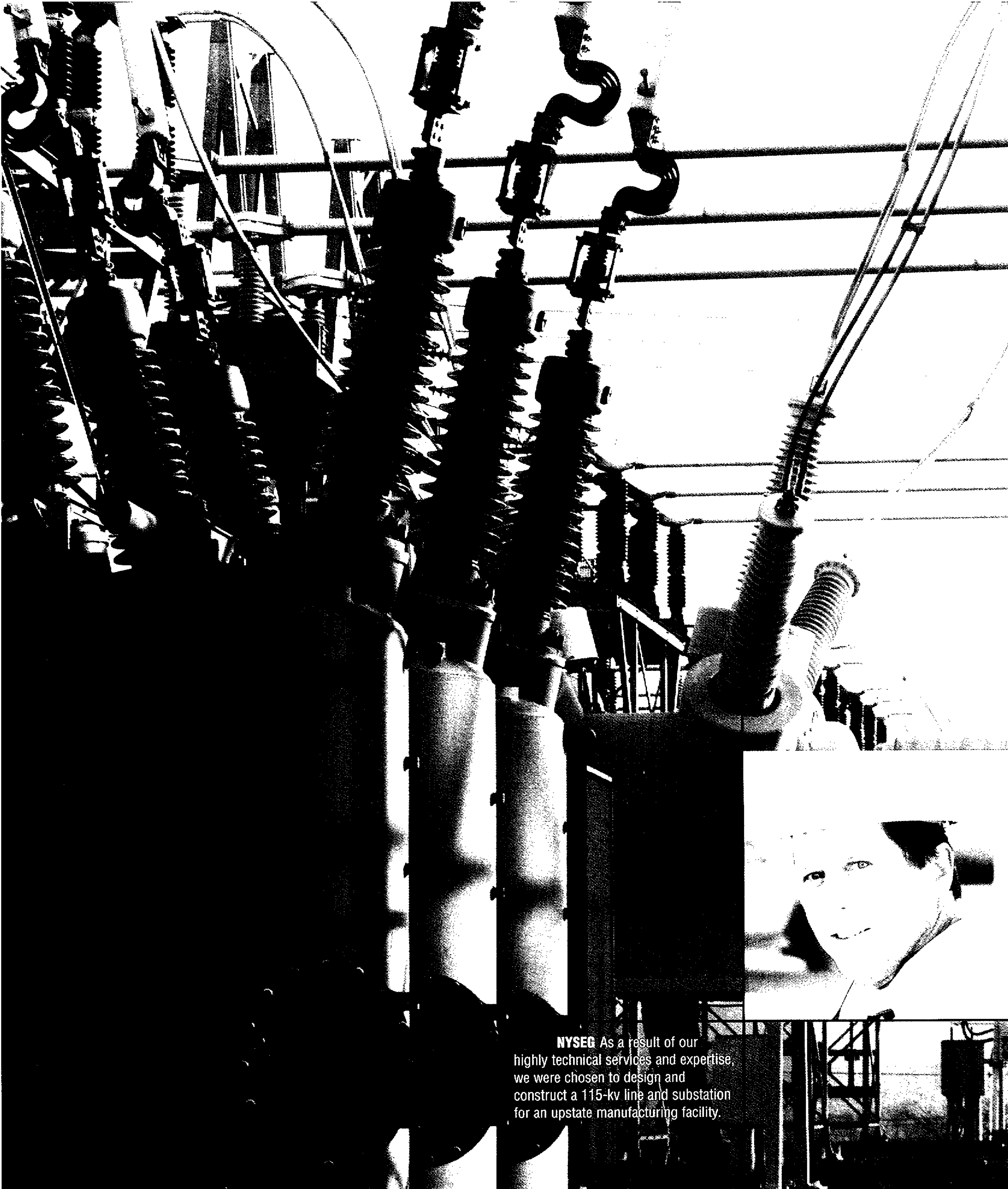
**NYSEG** Infrared sensor technologies are used to inspect transmission and distribution facilities to identify problems before they affect customers.

**Energy East** Our operating utilities have always met or exceeded their service reliability targets.



**RG&E** Our customers enjoyed the highest percentage of uninterrupted service in five years.





**NYSEG** As a result of our highly technical services and expertise, we were chosen to design and construct a 115-kv line and substation for an upstate manufacturing facility.

Although we completed the RGS Energy strategic combination, the earnings of RG&E were disappointing in 2002. We do, however, expect pending regulatory proceedings to result in improved earnings for both their natural gas and electric operations in 2003. We were not able to reach agreement with the New York State Public Service Commission (PSC) on long-term incentive-based rate plans at RG&E. On the other hand, the PSC did approve a long-term natural gas rate plan for NYSEG that extends through 2008. Long-term rate agreements are desirable because they benefit customers and shareholders alike, as they allow a sharing of the savings created by our strategic combinations.

2002 was a year in which we dedicated ourselves to the enormously complicated work associated with achieving the original cost savings and efficiency targets we established for our five strategic combinations. Specifically, we initiated three major merger-related efforts – *Integrating EExcellence*, *Project Spartan*, and *Information Technology and Supply Chain Optimization*.

# professional

I want to **hear a smile** in my customer's voice.

**CNG** We surpassed Service Quality standards for customer satisfaction, call center performance, call center response time and accuracy of meter reading.

**SCG** Our customers give us high marks for service (87.3%), in part due to our new "We Want to Know" line established for customers to register comments, suggestions and complaints.



**2002 HIGHLIGHTS** PROFESSIONAL

*Integrating EExcellence* is an employee driven, enterprise-wide, self-examination of how we conduct our business at each of the operating companies. Hundreds of key employees participated in an in-depth and introspective review, which generated thousands of ideas and identified the best practices throughout our organization, which will result in a substantial reengineering of various operating processes.

*Project Spartan* is a strategic sourcing approach across the enterprise, which will result in hundreds of new standardized contracts with suppliers that will deliver future cost savings. These comprehensive and unique efforts resulted in a number of intangible benefits. I, the operating company Presidents, our Chief Integration Officer and the head of Human Resources, spent five months, from June to November, two to three days a week, on *Integrating EExcellence* and phase one of *Project Spartan*. We brought our people together from the various operating companies for the first time, shared ideas, debated strengths and weaknesses and continued to build the culture of our new organization.

# safe & secure

I take very seriously my responsibility to protect our customers and our **complex operating system**.

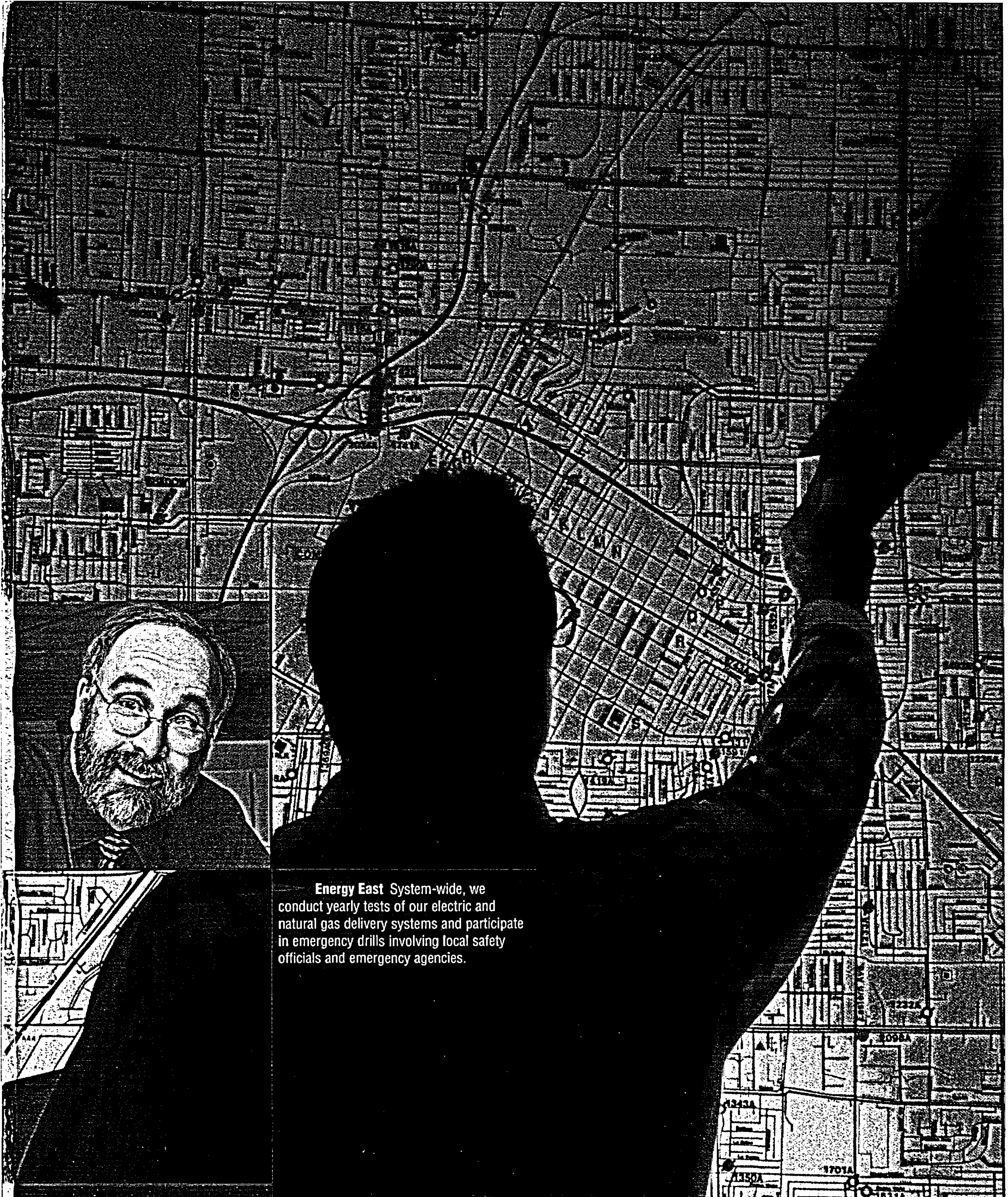
**CNG** The American Gas Association presented us an award for our significant achievement in the area of accident prevention.

**RG&E** Our Ginna nuclear plant completed the longest continuous uninterrupted run in history – 471 days.

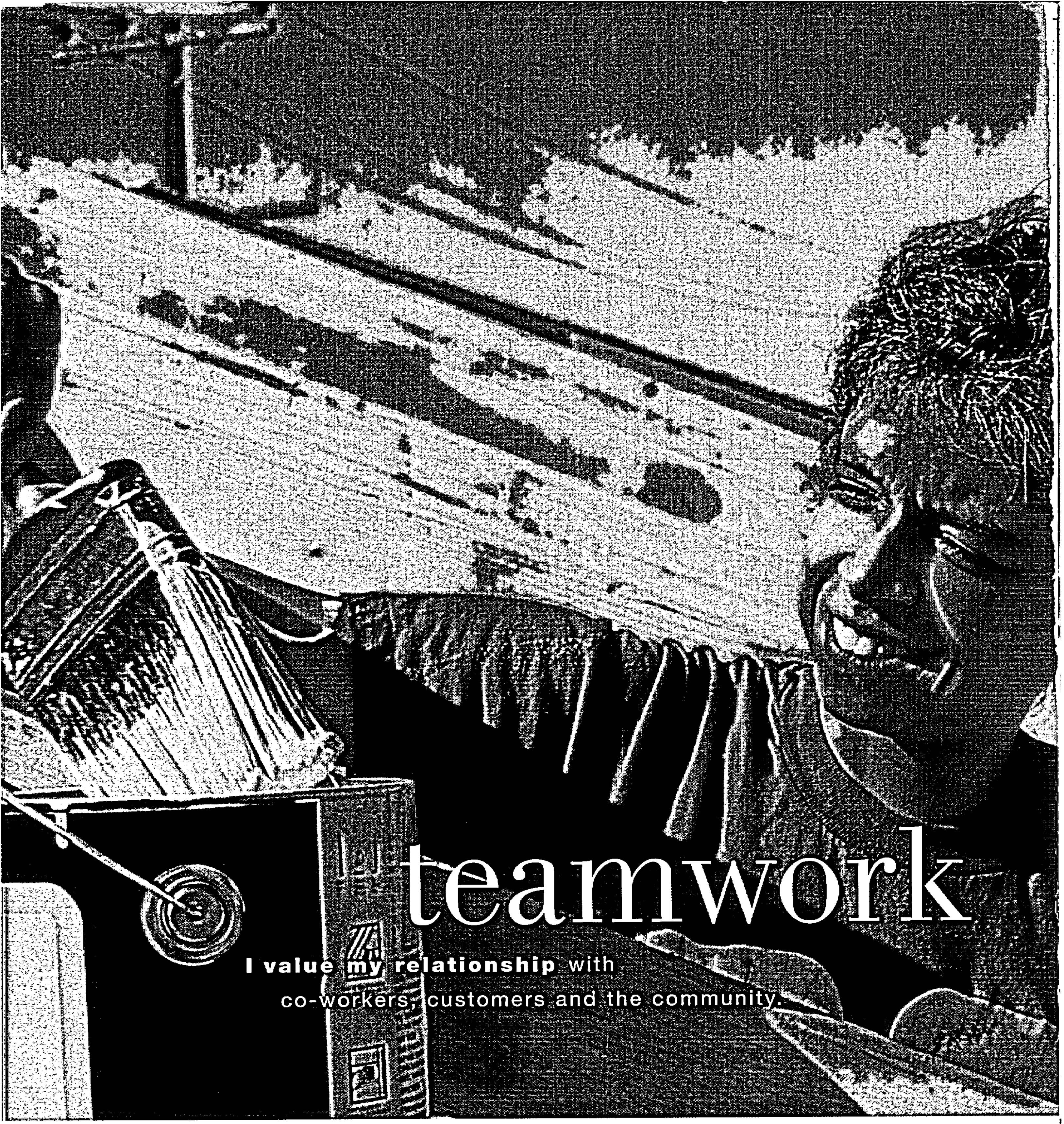
**CMP** We visit Maine schools with our Safety City display and talk with nearly 19,000 students every year.







**Energy East** System-wide, we conduct yearly tests of our electric and natural gas delivery systems and participate in emergency drills involving local safety officials and emergency agencies.



# teamwork

**I value my relationship** with
co-workers, customers and the community.

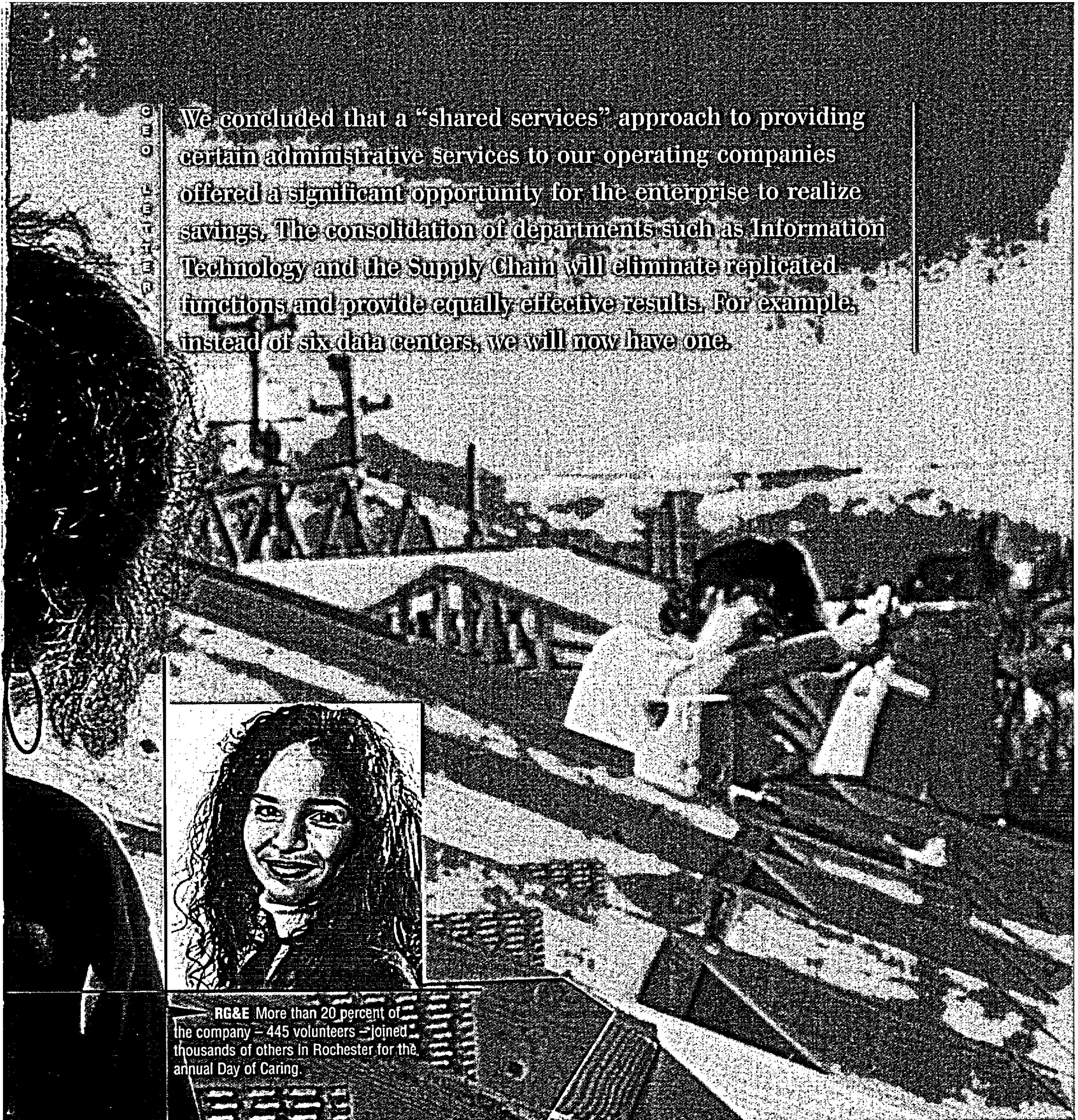
**Energy East** Our *Integrating EExcellence* initiative identified best practices to be implemented enterprise-wide.

**CMP** Our partnership with state and local economic development agencies resulted in a new financial services firm in South Portland and a distribution center in the City of Lewiston, creating the potential for 500 new jobs.



CEO LETTER

We concluded that a "shared services" approach to providing certain administrative services to our operating companies offered a significant opportunity for the enterprise to realize savings. The consolidation of departments such as Information Technology and the Supply Chain will eliminate replicated functions and provide equally effective results. For example, instead of six data centers, we will now have one.



**RG&E** More than 20 percent of the company – 445 volunteers – joined thousands of others in Rochester for the annual Day of Caring.

**NYSEG** Our award-winning Community Watch program has helped over 1,000 upstate New York neighbors in need of assistance in the past year.

**CNG** Employees joined a team of local officials, neighborhood representatives and area merchants to reconstruct Park Street in Hartford and helped develop businesses in that area.



These three initiatives, once fully implemented, are expected to produce annual savings in excess of $80 million and will begin to take hold in 2003. As you will note in our financial statements, a one-time pre-tax restructuring charge to earnings of $41 million was recorded in 2002 as a result of these initiatives.

While much of our focus in 2002 was on completing the RGS Energy merger and our integration initiatives, we did not lose sight of our most fundamental, yet critical, goal of providing outstanding customer service. Performance was excellent once again in 2002 as all of our utilities continued to meet their targets for reliability and customer satisfaction. Our long-term rate agreements add to customer satisfaction by providing them stable delivery prices for extended periods of time with a choice in their supplier of electricity or natural gas.

As I have reported in previous letters, we have been systematically exiting under-performing or non-core businesses. This year we sold Berkshire Services Solutions and a technology fund investment. Most of these non-core businesses we are exiting were inherited with our acquisitions.

# confidence

I anticipate, so **we are prepared**.

**Energy East** *Project Spartan* standardized materials and equipment specifications and identified common vendors for all of our operating companies.

**CNG** Fire and police personnel rely on us for training in the area of natural gas emergencies.



**2002 HIGHLIGHTS** CONFIDENCE

**CNG/SCG** An innovative supply and procurement contract was entered into to make sure that natural gas keeps flowing to our customers at the lowest price.

Energy East's remaining nonutility businesses are core related and focus on nonutility generation, liquid fuels distribution, retail energy marketing, telecommunications, propane distribution, district heating and cooling, FERC-regulated liquefied natural gas storage and energy services and construction.

As we look to 2003, our industry must continue to work at restoring investor and customer confidence that the deregulation of energy supply will provide the savings originally intended by policy makers and regulators. The Northeast, like other areas of the country including California, continues to lack the appropriate infrastructure, namely transmission and natural gas pipeline capacity, to support a fully competitive energy supply marketplace.

# integrity

**I am ethical** in all I do.

**Energy East** We have always, and will continue to act in accordance with the highest standards of ethical conduct, and meet any new requirements for financial transparency and accountability.



**2002 HIGHLIGHTS** · INTEGRITY

**Berkshire** Our employees completed restoration of a site along the Green River in Massachusetts with new plantings and a fully restored riverbank.

**Energy East** We complied with the increased auditing and reporting requirements of the Sarbanes-Oxley Act.



While Energy East has minimal electric generation, we do have a vested interest in making deregulation of energy supply successful because we want our customers to benefit from the lowest supply prices possible. Therefore, we have been at the forefront in promoting the combining of regional transmission organizations in New York, New England and the Mid-Atlantic states in order to provide greater supply liquidity in the marketplace, and asking regulators to develop financial incentives that encourage infrastructure investments. In New York new generating stations have not been built as state regulators thought they would be when they ordered us to sell our generating plants, and approximately one-third of existing New York power plants are now owned by financially troubled nonutility generators. Energy East will continue to be heard in the public policy arena on these matters.

Given the spotlight over the past year on the quality of corporate governance in both our industry and others, it is important to emphasize that Energy East is a company that has always taken corporate governance seriously and respects our investors' need for full disclosure. We strive to make our financial statements transparent. Additionally, our Board is structured to provide keen and objective oversight. Other than myself, all members of Energy East's Board of Directors are independent, and our Directors receive a portion of their compensation in Energy East stock. In fact, we are already in compliance with most of the proposed New York Stock Exchange rules on effective corporate governance.



**2002 HIGHLIGHTS**

**JAN 11** Dividend raised 4¢ to 96¢ per share

**FEB 22** Connecticut DPUC approves SCG and CNG long-term rate plans

**FEB 27** NYPSC approves NYSEG long-term electric rate plan and RGS Energy merger

**MAR 13** Energy East announces support for three-region RTO

**APR 1** System-wide natural gas supply and optimization contract extended

**APR 12** 24¢ common stock dividend declared

**MAY 1** *Project Spartan* begins review of supply chain

**MAY 15** Energy East receives high scores in customer satisfaction in a national independent survey

Every day we at Energy East are focused on meeting our customer obligations and executing our business strategies. Please take note of the value themes as you read this annual report. They represent how we conduct our business and what is important to the Energy East team.

Over the past three years, we have built a super regional, "pipes and wires" energy delivery company, and have consistently delivered shareholder value. We are confident that Energy East is getting positioned to deliver modest, but sustainable, earnings and dividend growth over the long term.

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

FEBRUARY 18 2003

Wes Von Schack

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

**JUN 15** $400 million long-term notes issued to fund RGS Energy merger

**JUN 17** Enterprise-wide *Integrating EExcellence* initiative begins

**JUN 25** Energy East 2001 annual report wins ARC award

**JUN 28** RGS Energy merger completed

**JUL 11** 24¢ common stock dividend declared

**JUL 31** 4% interest in Vermont Yankee nuclear plant sold

License renewal for RG&E's Ginna nuclear plant filed with NRC

Energy East receives high scores in power quality and reliability in a national independent survey

**AUG 8** CEO and CFO attest to the accuracy of current and previously filed financial statements

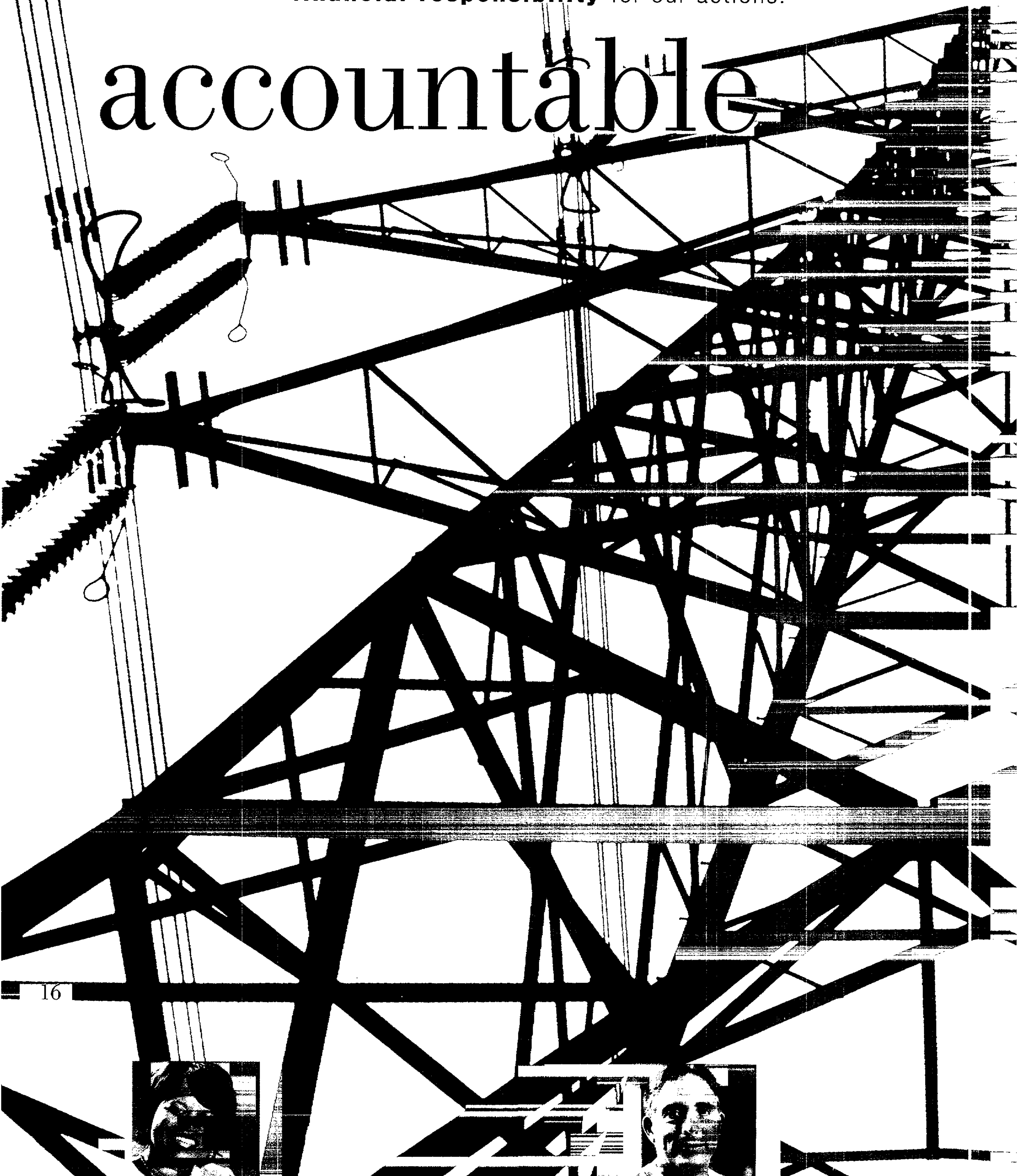
**OCT 11** 24¢ common stock dividend declared

**OCT 24** Energy East announces early retirement program at operating utilities

**NOV 20** NYPSC approves NYSEG natural gas long-term rate plan

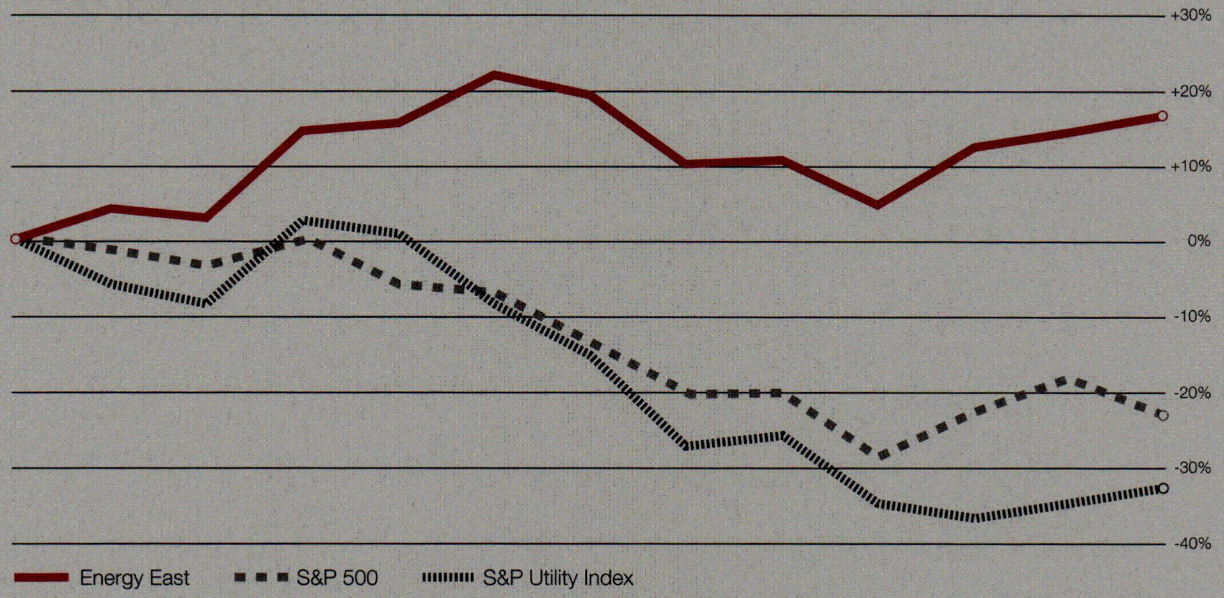
We take ownership and **financial responsibility** for our actions.

# accountable



# Financial Review

**Stock Performance** 2002








C01

| Per Common Share | 2002 | 2001 | % Change |
|---|---|---|---|
| Earnings | **$1.44** | $1.61 | (11) |
| Dividends Paid | **$.96** | $.92 | 4 |
| Book Value at Year End | **$16.97** | $15.26 | 11 |
| Price at Year End | **$22.09** | $18.99 | 16 |
| **Other Common Stock Information** (Thousands) | | | |
| Average Common Shares Outstanding | **131,117** | 116,708 | 12 |
| Common Shares Outstanding at Year End | **144,966** | 116,718 | 24 |
| **Operating Results** (Thousands) | | | |
| Total Operating Revenues | **$4,008,918** | $3,759,787 | 7 |
| Total Operating Expenses | **$3,416,742** | $3,122,899 | 9 |
| Net Income | **$188,603** | $187,607 | 1 |
| Energy Distribution: | | | |
| Megawatt-hours – | | | |
| Retail Deliveries | **26,869** | 23,238 | 16 |
| Wholesale Deliveries | **5,330** | 6,048 | (12) |
| Dekatherms – | | | |
| Retail Deliveries | **181,859** | 148,000 | 23 |
| Wholesale Deliveries | **7,074** | 9,298 | (24) |
| **Total Assets at Year End** (Thousands) | **$10,269,879** | $7,269,232 | 41 |

# highlights

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

## Liquidity and Capital Resources

### Restructuring

In 2002 Energy East Corporation (Energy East or the company) initiated a corporate restructuring 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, including $5 million for Central Maine Power Company (CMP), $26 million for New York State Electric & Gas Corporation (NYSEG) and a total of $10 million for The Berkshire Gas Company (Berkshire Gas), Connecticut Natural Gas Corporation (CNG) and The Southern Connecticut Gas Company (SCG). The restructuring expenses would have been $36 million higher, however Rochester Gas and Electric Corporation (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. 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 are $20 million for a voluntary early retirement program that will be paid from the companies' pension plans and $3 million for an involuntary severance program, primarily for salaried employees of the company's six operating utilities, and $1 million for other associated costs.

Those programs are expected to result in a decline in overall employee headcount of approximately 650, or 8%, by April 30, 2003. That includes approximately 70 from CMP, 260 from NYSEG, 245 from RG&E and 75 from Berkshire Gas, CNG and SCG. The employees affected by the involuntary severance program were notified in January 2003.

### Energy East and RGS Energy Merger

On June 28, 2002, Energy East completed its merger with RGS Energy. Under the merger agreement 45% of RGS Energy common stock, 15.6 million shares, was converted into 27.5 million shares of Energy East common stock valued at $612 million. The value of the shares issued was determined based on the market price of Energy East's stock at the end of the day on June 27, 2002. The remaining 55% of the RGS Energy common stock was exchanged for $753 million in cash, which was $39.50 per RGS Energy share. The purchase price was about $1.4 billion, which includes $11 million of merger-related costs. The transaction was accounted for using the purchase method. Energy East's consolidated statements of income and cash flows include RGS Energy's results of operations beginning with July 2002. (See Note 3 to the Consolidated Financial Statements.)

As a result of the merger RGS Energy became a wholly-owned subsidiary of Energy East. RG&E continues to be a wholly-owned subsidiary of RGS Energy and NYSEG became a wholly-owned subsidiary of RGS Energy.

### 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.

**Regional Transmission Organization (RTO) >** In July 2001 the Federal Energy Regulatory Commission (FERC) issued an order requiring the New York Independent System Operator (NYISO) and neighboring New England and Mid-Atlantic independent system operators (ISOs) to negotiate to form a single Northeast RTO. The NYISO

and other parties involved in negotiating the formation of the Northeast RTO participated in mediation facilitated by a FERC administrative law judge (ALJ), leading to a business plan detailing the process to develop a Northeast RTO. The business plan, coupled with an ALJ's report, were submitted to the FERC. NYSEG, CMP and RG&E have consistently advocated the formation of a Northeast/Mid-Atlantic RTO, including PJM Interconnection, L.L.C. (PJM), or functionally combined markets throughout the Northeast because they believe that a larger wholesale power market is essential to facilitate greater liquidity and competition.

In January 2002 the ISO New England, Inc. (ISO New England) and the NYISO entered into an agreement to consider forming an RTO, and PJM entered into an agreement to form common market systems with the Midwest ISO. The ISO New England and the NYISO submitted a joint petition to the FERC on August 23, 2002, asking for a declaratory order stating that a merger of the two ISOs, as described in the petition, would satisfy FERC requirements for an RTO. On November 22, 2002, the ISO New England and the NYISO withdrew their proposal, citing opposition from stakeholders, including CMP, NYSEG and RG&E. The companies opposed the proposal because, among other things, it failed to demonstrate that the benefits outweighed the costs and failed to recognize the need for a larger market.

In October 2001 FERC commenced a proceeding to consider national standard market design issues and on July 31, 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 January 2003. The companies generally support the proposed SMD because it would functionally combine the Northeast markets. The companies plan to file additional comments in 2003. The proposals in the SMD NOPR include the adoption of an energy market based on locational marginal pricing (LMP), which represents a significant change for some regions of the country. The NYISO already operates a market based on LMP, and ISO New England is in the process of developing and implementing an LMP system.

**Transmission Planning and Expansion** > In June and July 2001 FERC issued orders that addressed a number of transmission planning and expansion issues that would directly affect CMP, NYSEG and RG&E as transmission owners. The FERC orders discussed giving exclusive responsibility for the transmission planning process to a Northeast RTO, rather than the transmission owners. The orders also discussed redefining the cost-sharing responsibilities of interconnecting generators for transmission expansion costs. On April 24, 2002, and August 16, 2002, FERC issued NOPRs regarding generation interconnection terms, conditions and cost allocation. FERC is expected to issue a final rule in 2003. Additional transmission planning and expansion proposals are included in the SMD NOPR. The company is unable to predict the ultimate effect, if any, of the expected rulemakings on its transmission system or on future capital expenditures.

On January 15, 2003, FERC issued a proposed policy statement on transmission pricing. FERC proposes a 50 basis point return on equity adder on facilities over which transmission owners turn control to an RTO. The NYISO and ISO New England satisfy most of the requirements of an RTO. Additionally, 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 is evaluating FERC's policy proposal and plans to file comments.

**Electric Transmission Rates** > On June 28, 2002, CMP made its required annual informational filing with FERC updating its local transmission formula rates. CMP's annual transmission revenue requirement increased by $0.6 million reflecting increased costs associated with transmission constraints during periods of high demand. Rates pursuant to this filing became effective June 1, 2002, and reflect actual cost and revenues from the 2001 calendar year.



**Sale of Nuclear Interests** > (See Note 10 to the Consolidated Financial Statements.) On July 31, 2002, Vermont Yankee Nuclear Power Corporation sold the Vermont Yankee nuclear power plant, including CMP's

4% ownership interest, to Entergy Corporation. Any benefits realized from the sale, which are expected to be less than $1 million, will be 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 operating license for the plant expires.

In November 2001 NYSEG sold its 18% interest in the Nine Mile Point 2 nuclear generating station (NMP2) to Constellation Nuclear. In October 2001 the NYPSC issued an order approving the sale. For its share of NMP2, NYSEG received at closing $59 million in cash and a $59 million 11% promissory note. On April 12, 2002, Constellation Nuclear paid the remaining balance plus accrued interest on the promissory note. (See Note 10 to the Consolidated Financial Statements.)

Upon completion of the sale of NMP2, an asset sale gain of approximately $110 million was recorded, in accordance with the NYPSC's order, as a regulatory liability under Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (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.

**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. The revenue requirement related to transmission services is established by FERC. Recovery of stranded costs, primarily overmarket nonutility generator (NUG) contracts and nuclear decommissioning costs, has been provided for under Maine's Restructuring Law. 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.

On June 25, 2002, the MPUC approved a filing allowing CMP's distribution prices to change effective July 1, 2002. As a result, distribution rates for customers not subject to special contracts decreased by 4.84%. The reduction reflects a decrease of 3.03% in distribution rates resulting from expiring amortizations and the application of a price cap mechanism, and an additional one-time decrease of 1.81% reflecting over-collections of certain costs, such as for low-income assistance programs and insurance proceeds related to environmental remediation.

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

Under Maine 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 2003. 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 Law. CMP's revenues and purchased power costs will fluctuate, however, as its status as a standard-offer provider changes. (See Operating Results for the Electric Delivery Business and Note 9 to the Consolidated Financial Statements.)

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 2003 the MPUC chose suppliers of standard-offer electricity for the six months beginning March 1, 2003: FPL Energy Power Marketing, Inc. for medium class customers and Select Energy, Inc. for larger customers.

**MPUC Stranded Cost Proceeding** > In December 2001 the MPUC approved a stipulation among CMP, the Office of the Public Advocate and the Industrial Energy Consumer Group settling all issues related to the setting of CMP's stranded cost revenue requirement for the period March 1, 2002, through February 28, 2005. In January 2002 CMP submitted a compliance filing to the MPUC setting the three-year stranded cost revenue requirement.

The amount of the revenue requirement reflects the ongoing costs related to CMP's remaining nondivested generating resources and the decommissioning of two nuclear power plants, offset by revenues to be received for the output from the remaining nondivested generating resources and amortization of amounts from CMP's gain on sale of generation assets account. Under the terms of the stipulation, parties can request a review of stranded costs if revenues differ significantly from anticipated costs. On December 17, 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. As ordered by the MPUC in this proceeding, CMP made its initial filing on February 7, 2003, concluding that no change in the current stranded costs rate is appropriate. CMP expects the MPUC to act on its filing by July 1, 2003.

**NYSEG Electric Rate Plan** > 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. The electric rate plan resulted from a settlement reached by the company, NYSEG, RGS Energy, RG&E, the NYPSC Staff, the Attorney General of the State of New York, the New York State Consumer Protection Board, Multiple Intervenors and other parties. NYSEG's 1998 electric rate and restructuring agreement and an NYPSC Order issued in January 2002, regarding temporary rates for NYSEG's electric customers, were superseded by the NYPSC February 2002 Order. The NYPSC February 2002 Order also provided for the discontinuance of several outstanding NYSEG proceedings. 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 now 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 by 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 returns on equity in excess of 15.5% for 2002, and equal sharing on the greater of returns on equity 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.

**NYPSC-mandated Contracts with Two Customers** > In March and April 2002 the NYPSC issued orders directing NYSEG to enter into long-term electric service contracts with Nucor Steel Auburn, Inc. and Corning Incorporated, that in NYSEG's opinion contain unduly low and preferential rates. In April 2002 NYSEG petitioned for rehearing of these orders on the basis that each order, and each underlying contract, violates law, NYSEG's tariffs and NYPSC guidelines. In May 2002 the NYPSC denied NYSEG's petitions for rehearing. On July 24, 2002, NYSEG filed a petition with the New York State Supreme Court, Albany County, asking the court to overturn the NYPSC's orders directing NYSEG to enter into the long-term electric service contracts because the rates and the terms of those mandated contracts are unduly preferential and violate the law, NYSEG's tariffs and the NYPSC's guidelines. Oral arguments were held in the proceeding on September 13, 2002. On December 9, 2002, the State Supreme Court dismissed NYSEG's petition. NYSEG has appealed that dismissal to the Appellate Division, Third Department, of the New York State Supreme Court. On September 24, 2002, and November 25, 2002, consistent with the NYPSC's orders, NYSEG signed the mandated contracts under protest, subject to review by the courts.

Lost revenues associated with these long-term electric service contracts are recovered through the asset sale gain account created by NYSEG's sale in 2001 of its interest in NMP2 and do not affect earnings. After giving effect to the amortization of the asset sale gain account to fund the first year of the electric rate reduction (See NYSEG Electric Rate Plan), the remaining balance would be entirely consumed by discounts offered to these two large industrial customers. NYSEG believes that the remaining balance should not be used for discounts provided to just two customers, but should be available to fund other economic development projects and for the recovery of uncontrollable costs.

**Nonutility Generation >** 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 2002 this cumulative overpayment was more than $170 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 motion was denied by the court in September 2002. Unless a settlement can be reached, the matter is expected to proceed to trial.

CMP and NYSEG together expensed approximately $611 million for NUG power in 2002. They estimate that their combined NUG power purchases will total $613 million in 2003, $632 million in 2004, $642 million in 2005, $578 million in 2006 and $544 million in 2007. 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 2002, averaged 8.7 cents per kilowatt-hour for CMP and 8.3 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 9 to the Consolidated Financial Statements.)

**RG&E 2002 Electric and Gas Rate Proceeding >** On February 15, 2002, RG&E filed a request with the NYPSC for new electric and natural gas rates to go into effect on January 15, 2003. Subsequently, the date for a decision by the NYPSC was extended to March 2003 with a "make-whole" provision under which rates and any associated mechanisms would be adjusted to put RG&E and its customers in the same position they would have been had rates been allowed to go into effect as of January 15, 2003. The filing included both a traditional single-year filing and elements of a multi-year proposal for potential settlement negotiations. The single-year filing, as updated, provides a basis to increase annual electric rates by $40 million, or 5.7%, and increase annual natural gas rates by $19 million, or 6.6%, for the 12-month period ending June 30, 2003. RG&E's current base rates for electric and natural gas service will remain in effect until a new order is issued by the NYPSC. A lack of progress did not justify continuation of settlement discussions at that time and the parties proceeded on a litigation track. Evidentiary hearings took place in late October 2002. On December 17, 2002, the ALJ in this proceeding issued a recommended decision that, if approved, would result in a $9 million, or 3.3%, overall increase for natural gas service and no increase for electric service. Briefs on exception to the recommended decision were filed on January 7, 2003. Briefs opposing exceptions were filed on January 17, 2003. Following the submission of briefs settlement conferences in the natural gas proceeding were held.

As part of the current RG&E rate proceeding, the ALJ found RG&E to have excess electric earnings of $45 million, including interest, from RG&E's prior rate plan. RG&E continues to believe its reserve of $26 million for the estimated five-year excess earnings is appropriate. The calculation of the excess earnings will be subject to final approval by the NYPSC. RG&E is unable to predict what the NYPSC's ultimate determination of excess earnings under RG&E's prior rate plan will be.

**Ginna Station >** Several nuclear power plant operators have identified defects in their reactor vessel heads, which has prompted heightened Nuclear Regulatory Commission (NRC) oversight. During the summer of 2001 RG&E thoroughly reviewed this issue and an inspection plan was implemented during the spring 2002 refueling outage. Although the inspection demonstrated that the Ginna nuclear generating station (Ginna) could continue to operate with the existing head, RG&E decided to replace the reactor vessel head in order to avoid significant expenditures associated with maintenance, inspections and length of future outages. The replacement is scheduled to be completed during the fall 2003 refueling outage. The duration of the 2003 refueling outage is not expected to be significantly different than the duration of previous outages. The cost of the replacement is estimated to be $13 million and is expected to be recovered in rates.

**Ginna Relicensing** > The Ginna station operating license expires in 2009. On July 31, 2002, RG&E filed a license renewal application with the NRC, which, if approved, would extend the license through September 2029. The NRC has deemed the application complete. The NRC held two sets of public meetings in 2002, and plans to hold one more in 2003. RG&E's renewal application was unopposed. A decision on this matter is expected by the end of 2004.

## 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, optimization and management of certain natural gas supply, transportation and storage services, including portfolio management. The alliance provides the companies with greater supply flexibility, enhances the benefits of a larger natural gas portfolio and is based on sharing incremental savings. The companies still own and control their natural gas assets and work with BP Energy to obtain the lowest cost supply while maintaining reliability of service. The Energy East natural gas companies have received the required regulatory approvals concerning the alliance.

RG&E entered into a two-year supply portfolio management agreement that began April 1, 2002, with Dynegy Marketing and Trade, for Dynegy to assist RG&E in the cost-effective management of RG&E's firm contractual rights to natural gas supply, transportation and storage services. The agreement is designed to ensure that RG&E can reliably meet its customers' supply requirements while seeking to minimize the annual delivered cost of natural gas. On October 16, 2002, Dynegy announced that it would exit the marketing and trading business over the next several months. As a result of Dynegy's actions RG&E terminated its agreement with Dynegy and entered into a new portfolio management agreement with Entergy-Koch Trading, LP. The new arrangement with Entergy-Koch will extend through March 31, 2004, and includes the same reliability and cost-minimization objectives as the prior agreement with Dynegy. RG&E is assessing its position relative to the Dynegy termination and will take appropriate action to resolve any outstanding issues.

**NYSEG Natural Gas Rate Plan** > On November 20, 2002, the NYPSC approved the joint proposal that NYSEG filed with the NYPSC on September 13, 2002, and that had been endorsed by NYPSC Staff, the NY State Consumer Protection Board, large customer groups and numerous gas marketers. The approved natural gas rate plan became effective October 1, 2002, freezes overall delivery rates through December 31, 2008, implements 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 returns on equity 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.

**Connecticut Regulatory Proceedings** > During 2001 the Connecticut Office of Consumer Counsel (OCC) filed appeals in State Superior Court arguing that the Connecticut Department of Public Utility Control's (DPUC) order in December 2000 approving an SCG multi-year incentive rate plan (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, extends the approved IRPs for an additional year through September 2005 and maintains an earnings sharing mechanism (ESM) that generally shares any earnings above the authorized returns on equity 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.

In June 2002 the DPUC initiated proceedings to address the need for an interim rate decrease for SCG. Upon review of SCG's financial reports the DPUC concluded that a rate decrease was not required. SCG's earnings in excess of its allowed rate of return were primarily the result of merger-enabled gas costs savings and provided a direct benefit to customers because of the ESM that is an integral part of SCG's IRP.

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. The DPUC has postponed its final decision in this matter.

**Berkshire Gas Rate Increase** > 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 less 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' proposal for service quality enhancements will be addressed in another proceeding.

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

**NYPSC Collaborative on End State of Energy Competition** > In March 2000 the NYPSC instituted a proceeding to address the future of competitive natural gas and electricity 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. 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. The embedded cost of service studies have been filed and are currently under review.

## Other Businesses

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

**Sale of Other Businesses** > The company continues to rationalize its nonutility businesses to ensure they fit its strategic focus. On August 12, 2002, Berkshire Service Solutions, Inc., an energy services provider and a subsidiary of Berkshire Energy Resources (Berkshire Energy), was sold at a loss of about $2 million. Berkshire Energy is a wholly-owned subsidiary of Energy East. During the fourth quarter of 2002 CNE Venture Tech Inc., a subsidiary of Connecticut Energy Corporation (CNE), sold its 5% interest in the Nth Power Technologies Fund II, LP, at a loss of about $1 million.

**Maine Natural Gas >** In June 2001 Maine Natural Gas began construction of a new natural gas distribution system to serve the towns of Bowdoin, Brunswick and Topsham, Maine. It has served natural gas to certain larger customers since November 2001 and began serving residential and commercial customers in early 2002. Maine Natural Gas is also expanding its distribution system in Windham and Gorham, Maine.

**Natural Gas Storage Facility >** In August 2001 Seneca Lake Storage, Inc. (SLSI), a subsidiary of the company, announced plans to develop a high-deliverability natural gas storage facility in depleted salt caverns in the Town of Reading, New York. SLSI is currently assessing the demand for the facility. The storage facility would be linked to interstate pipelines, have a working gas capacity of 300,000 dekatherms (dth) and be capable of delivering up to 50,000 dth a day. In February 2002 FERC issued a certificate allowing the construction of certain natural gas storage facilities and requiring that the facilities be completed and made available for service within one year of the order. In December 2002 FERC granted a request by SLSI to modify the certificate to extend by one year the date within which SLSI has to complete construction of the proposed facilities and initiate service.

## Other Matters

### Accounting Issues

**Statement 71 >** Statement 71, Accounting for the Effects of Certain Types of Regulation, allows companies that meet certain criteria to capitalize, as regulatory assets, incurred 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, Connecticut, Maine and Massachusetts; however, the company cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC or DTE 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.

**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 company adopted Statement 143 as of January 1, 2003. The adoption of Statement 143 did not have a material effect on the company's financial position or results of operations. (See Note 1 to the Consolidated Financial Statements.)

**Statement 145 >** In April 2002 the FASB issued Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. Early application of the provisions of Statement 145 is encouraged and the company elected to do so beginning in April 2002. The company now classifies the aggregate of gains and/or losses from the early extinguishment of debt as other income or other deductions on its income statement, as appropriate, instead of as an extraordinary item. The company has reclassified such extraordinary items presented on its income statements in prior periods. The remaining provisions of Statement 145 did not have a material effect on the company's financial position or results of operations.

**Statement 146 >** In June 2002 the FASB issued Statement of Financial Accounting Standards No. 146, Accounting for Costs Associated with Exit or Disposal Activities. Statement 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred, rather than at a plan or commitment date for the exit or disposal activity. It establishes fair value as the objective for initial measurement of the liability. The provisions of Statement 146 are effective for exit or disposal activities initiated after December 31, 2002. The company and its subsidiaries have determined that their adoption of Statement 146, on January 1, 2003, did not have a material effect on their results of operations or financial position.

## Contractual Obligations and Commercial Commitments

At December 31, 2002, the company's contractual obligations and commercial commitments that will become due during the next five years are:

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| (Thousands) | | | | | |
| **Contractual Obligations** | | | | | |
| Long-term debt | $542,909 | $41,322 | $59,229 | $338,967 | $230,695 |
| Capital lease obligations | 2,495 | 2,517 | 2,382 | 2,190 | 2,055 |
| Operating leases | 16,572 | 15,663 | 13,955 | 12,281 | 12,222 |
| Nonutility generator purchase power obligations | 613,398 | 631,647 | 641,954 | 578,011 | 543,644 |
| Nuclear plant obligations | 58,134 | 54,078 | 60,448 | 61,742 | 52,045 |
| Unconditional purchase obligations | 297,123 | 260,024 | 218,672 | 188,439 | 175,622 |
| Other long-term obligations | 8,015 | 8,735 | 8,816 | 6,819 | 5,909 |
| **Total contractual cash obligations** | $1,538,646 | $1,013,986 | $1,005,456 | $1,188,449 | $1,022,192 |
| **Other Commercial Commitments** | | | | | |
| Lines of credit | $754,750 | $258,000 | $258,000 | – | – |
| Standby letters of credit | 334,100 | 334,100 | – | – | – |
| Guarantees | 61,600 | 2,500 | – | – | – |
| **Total commercial commitments** | $1,150,450 | $594,600 | $258,000 | – | – |

Energy East has two revolving credit agreements in which it 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 was 0.59 to 1.00 at December 31, 2002.

CMP has a revolving credit facility, which is secured by its accounts receivable, in which it 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 stockholders 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, 2002, CMP's consolidated total debt ratio was 33.6% and its interest coverage ratio was 3.73 to 1.00.

NYSEG and RG&E have a joint revolving credit agreement in which they 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, 2002, the ratio of earnings before interest expense and income tax to interest expense was 3.4 to 1.0 for NYSEG and 2.3 to 1.0 for RG&E, and the ratio of total indebtedness to total capitalization was 0.53 to 1.00 for NYSEG and 0.52 to 1.00 for RG&E.

NYSEG has two letters of credit and reimbursement agreements 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, 2002.

## Critical Accounting Policies

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 policies include the determination of the appropriate accounting for its pensions and other postretirement benefits, the effects of utility regulation on its financial statements and its risk management activities and the estimates and assumptions used to complete its annual goodwill and other intangibles impairment analyses.

**Goodwill and Other Intangible Assets** > As required by Statement 142, effective January 1, 2002, 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 test includes various assumptions. The primary assumptions are the discount rate and forecasted cash flows. Changes in those assumptions could have a significant effect on the company's determination of an impairment. (See Note 4 to the Consolidated Financial Statements.)

**Pension and Other Postretirement Benefit Plans** > 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 also 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, 2002, the company decreased the discount rate from 7.0% to 6.5% and the expected return on plan assets from 9.0% to 8.75% effective January 1, 2003. (See Results of Operations – Other Items.)

**Risk Management** > See Quantitative and Qualitative Disclosures About Market Risk and Note 1 to the Consolidated Financial Statements.

**Utility Regulation** > The company's regulated utilities are subject to regulation by their respective state regulatory commissions and the FERC. 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 upon cost basis regulation reviewed and approved by those regulatory commissions. (See Accounting Issues Statement 71.)

## Investing and Financing Activities

**Investing Activities** > Capital spending totaled $229 million in 2002, $223 million in 2001 and $168 million in 2000, including capital spending for RGS Energy and nuclear fuel for RG&E beginning July 1, 2002. Capital spending does not include the amounts representing the company's merger transaction for RGS Energy in 2002 nor the four merger transactions in 2000. (See Note 3 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 and compliance with environmental requirements and governmental mandates.

Capital spending is projected to be $338 million in 2003, which includes RGS Energy and nuclear fuel. It is expected to be paid for with internally generated funds and will be primarily for the same purposes described above and merger integration. (See Note 9 to the Consolidated Financial Statements.)

The company's pension plans generated pretax noncash pension income (net amounts capitalized) of $70 million in 2002, compared to $76 million in 2001 and $68 million in 2000. The company expects noncash pension income (net amounts capitalized) for 2003 to decline, affecting earnings by approximately 15 cents per share as compared to 2002. That expected decrease is due to the significant equity market declines over the past several years and revised actuarial assumptions including the discount rate used to compute its pension liability (reduced from 7% to 6.5% as of December 31, 2002) and return on assets (reduced from 9% to 8.75% effective January 1, 2003). The company anticipates minimal funding requirements in 2003 as total plan assets approximates the projected benefit obligation. The company is currently unable to predict the effect that future equity market performance will have on pension income for 2004 and beyond. (See Note 15 to the Consolidated Financial Statements.)

**Financing Activities** > (See Note 6 to the Consolidated Financial Statements.)

The company raised its common stock dividend 4% in January 2003 to a new annual rate of $1.00 per share.

During 2002 the company repurchased 113,500 shares of its common stock at an average price of $18.85 per share. Future repurchases will depend on expected cash flows, alternative uses of cash, and overall economic and market conditions.

In August 2001 the company began issuing new common shares through its Dividend Reinvestment and Stock Purchase Plan (DRIP) rather than purchasing them on the open market. During 2002 the company issued 852,824 shares at an average price of $20.92 per share through its DRIP, substantially out of treasury stock. The company expects to issue approximately one million shares per year under this plan.

In December 2002 the company amended its DRIP to allow nonshareholders who reside in Connecticut, Maine, Massachusetts or New York State to enroll directly in the Plan by making an initial cash investment.

The company and its subsidiaries have credit agreements with various expiration dates in 2003 and 2005. The agreements provided for maximum borrowings of $755 million at December 31, 2002 and 2001. (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 $322 million of such short-term debt outstanding at December 31, 2002, and $173 million outstanding at December 31, 2001. The weighted-average interest rate on short-term debt was 2.1% at December 31, 2002 and 2.6% at December 31, 2001.

In May 2001 the company filed a shelf registration statement with the Securities and Exchange Commission (SEC) to sell up to $1 billion in an unspecified combination of debt and trust preferred securities. The company has issued $995 million of debt and trust preferred securities under the shelf registration statement to fund the cash portion of the consideration for the merger with RGS Energy, for general corporate purposes, such as short-term debt reduction and to fund an equity contribution to NYSEG in 2001. (See Energy East and RGS Energy Merger.)

In June 2002 the company issued $400 million of 6.75% 10-year notes due June 2012 under the shelf registration statement described above. The proceeds were used to help fund the RGS Energy merger.

In July 2002 the company entered into a fixed-to-floating interest rate swap on the company's 5.75% notes due November 2006. The company receives a fixed rate of 5.75% and will pay a rate based on the six month London Interbank Offered Rate (LIBOR) plus 1.565%, on a notional amount of $250 million through November 2006.

In July 2002 the company terminated a fixed-to-floating interest rate swap on the company's 8.05% notes due November 2010. The company received $16 million, the value of the swap on the date of termination, and will amortize about $15 million of that gain over the remaining life of the notes.



CMP issued the following Series E Medium Term Notes, the proceeds of which were used to repay $50 million of maturing medium-term notes, as well as short-term debt and for general corporate purposes in 2002: in May 2002 – $37.5 million, 6.50%, due May 2009 and $37.5 million, 6.65%, due May 2012; in August 2002 – $15 million,

5.70%, due August 2012; in September 2002 – $15 million, 4.25%, due September 2007; and in November 2002 – $15 million, quarterly adjustable rate based on the three month LIBOR plus 0.6%, due January 2006.

In May 2002 NYSEG redeemed, at a premium, $150 million of 8 7/8% Series first mortgage bonds due November 1, 2021, and redeemed, at par, the remaining $21.34 million of two 9 7/8% Series first mortgage bonds due 2020. The redemptions were financed with internally generated cash and the proceeds from the prepayment of a promissory note by Constellation Nuclear in April 2002. (See Sale of Nuclear Interests). NYSEG incurred a $10 million reduction to earnings in the second quarter of 2002 as a result of these redemptions, but will save over $16 million each year in interest costs. (See Other Matters, Statement 145.)

In November 2002 NYSEG issued $150 million of 4 3/8% unsecured notes due November 2007 and $100 million of 5 1/2% unsecured notes due November 2012. NYSEG used the net proceeds from those notes to refund commercial paper that was used in October 2002 to repay $150 million of maturing 6 3/4% Series first mortgage bonds and to repay $100 million of 8.30% Series first mortgage bonds that were called on December 15, 2002.

In 2003 NYSEG plans to call its remaining first mortgage bonds: $50 million of 7.55% Series first mortgage bonds callable on April 1, 2003, and $100 million of 7.45% Series first mortgage bonds callable on July 15, 2003. Additional financing needed by NYSEG to call its remaining first mortgage bonds is expected to be completed in June 2003. Through financial instruments issued in September 2002, NYSEG has locked in the 10-year treasury rate component of that financing at an average rate of 4.085%.

On January 9, 2003, RG&E used a $50 million 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 to mature in 2014.

In July 2002 CNG paid at maturity $10 million of medium term notes using short-term debt. In October 2002 CNG redeemed $3.5 million of Series AA first mortgage bonds, including $2.5 million pursuant to a sinking fund provision and $1 million at a premium, using short-term debt.

## 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 companies' 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 companies handle 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 companies 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 companies are exposed to risk resulting from interest rate changes on their variable-rate debt and commercial paper. The company and its subsidiaries use interest rate swap agreements to manage interest rate risk and/or 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 companies estimate that, at December 31, 2002, a 1% change in average interest rates would change annual interest expense for variable rate debt by about $4.6 million for Energy East, including $0.2 million for CMP, $1.3 million for NYSEG and $0.7 million for RG&E. (See Notes 6 and 12 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, NYSEG and RG&E due to volatility experienced in both the electric and natural gas wholesale markets. The companies manage this risk through a combination of regulatory mechanisms, such as allowing for the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. These measures mitigate the companies' 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. (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 2003 the MPUC chose suppliers of standard-offer electricity for the six months beginning March 1, 2003: FPL Energy Power Marketing, Inc. for medium class customers and Select Energy, Inc. for larger customers.

All of Energy East's natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. (See Natural Gas Supply Agreements, NYSEG Natural Gas Rate Plan and Connecticut Regulatory Proceedings.)

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

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 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. Based on the results from the enrollment period that ended December 31, 2002, approximately 30% 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 calendar years 2003 and 2004 the supply component is based on average electricity forward prices for 2003 and 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 is actively hedging the load required to serve customers who select the bundled rate option. As of January 31, 2003, NYSEG's load was 93% hedged for on-peak periods and 87% hedged for off-peak periods in 2003 and 86% hedged for both on-peak and 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 2003 and $1 million in 2004. The percent 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 and natural gas. Under its electric settlement, RG&E's electric rates were capped at specified levels through June 30, 2002. 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 31, 2003, RG&E's load was 90% hedged for on-peak periods and fully hedged for off-peak periods in 2003 and fully hedged for both on-peak and off-peak periods in 2004. A fluctuation of $1.00 per megawatt-hour in the price of on-peak electricity would change earnings by $0.2 million in 2003. The percent 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 has filed a request with the NYPSC for new electric rates commencing in January 2003. The NYPSC has not ruled on the rate request; therefore, RG&E's current fixed electric rates will remain in effect until

a new rate order is issued. A new rate order is expected to be issued in March 2003, for electric rates retroactive to January 2003. (See RG&E 2002 Electric and Gas Rate Proceeding.)

While owned coal-fired and nuclear 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 and the use of derivative contracts.

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 companies' 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 companies 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. (See Note 15 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 companies' ability to compete in the rapidly changing and increasingly competitive electricity and/or natural gas utility markets; regulatory uncertainty in a politically-charged environment of changing energy prices; the operation of the NYISO and ISO New England; 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 now that most generation assets have been sold; 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, CMP Group, CNE, CTG Resources and RGS Energy with its operations and achieve anticipated 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 companies are 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 companies' publicly disseminated documents and filings. The companies undertake 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 the various mergers completed by the company, its results of operations include for 2002: RGS Energy beginning with July 2002; and for 2000: CNE beginning with February 2000 and CMP Group, CTG Resources and Berkshire Energy beginning with September 2000.

| (Thousands, except per share amounts) | **2002** | 2001 | 2000 | 2002 over 2001 Change | 2001 over 2000 Change |
|---|---|---|---|---|---|
| Operating Revenues | **$4,008,918** | $3,759,787 | $2,959,520 | 7% | 27% |
| Operating Income | **$592,176** | $636,888 | $513,921 | (7%) | 24% |
| Net Income | **$188,603** | $187,607 | $235,034 | 1% | (20%) |
| Average Common Shares Outstanding | **131,117** | 116,708 | 114,213 | 12% | 2% |
| Earnings Per Share, basic and diluted | **$1.44** | $1.61 | $2.06 | (11%) | (22%) |
| Dividends Paid Per Share | **$.96** | $.92 | $.88 | 4% | 5% |

## Earnings Per Share

Earnings per share for 2002 were $1.44 compared to $1.61 for 2001, and include the nonrecurring items shown in the following table. The decrease in earnings for 2002 excluding nonrecurring items 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 include: 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 and 7 cents per share for a loss on early retirement of debt. Those decreases were significantly offset by increases of 29 cents per share due to lower natural gas costs, which includes 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; and 19 cents per share due to the elimination of goodwill amortization in 2002.

Earnings per share for 2001 were $1.61 compared to $2.06 for 2000, and include the nonrecurring items shown in the following table. The increase in 2001 earnings excluding nonrecurring items was primarily due to 20 cents per share for cost control efforts, 10 cents per share due to earnings from the merged companies, 1 cent per share for a loss on early retirement of debt in 2000 and 4 cents per share for a loss on the sale of XENERGY in 2000. Those increases were partially offset by 23 cents per share for lower electric and natural gas deliveries due to warmer weather and 13 cents per share for reduced electric transmission revenues.

| | **2002** | 2001 | 2000 |
|---|---|---|---|
| Earnings per share, basic and diluted | **$1.44** | $1.61 | $2.06 |
| Restructuring expenses | **.19** | – | – |
| Writedown of investment in NEON Communications (See Note 12 to the Consolidated Financial Statements) | **.06** | .39 | – |
| Benefit from sale of coal-fired generation assets | **-** | – | (.07) |
| **Earnings Per Share, excluding nonrecurring items** | **$1.69** | $2.00 | $1.99 |

The company provides information on earnings exclusive of nonrecurring items because it believes this information may be helpful to investors in assessing the company's results of ongoing operations. The company cautions investors that its view of nonrecurring items may differ from that of other companies and earnings exclusive of nonrecurring items should not be used as a surrogate for reported earnings prepared in accordance with generally accepted accounting principles.

## Other Items

Other operating expenses includes net periodic pension benefit income of $70 million in 2002, $76 million in 2001 and $68 million in 2000. Other operating expenses would have been $6 million lower for 2002 and would have been $8 million higher for 2001 without those changes in net periodic pension benefit income. Net periodic pension benefit income represented 22% of net income for 2002, 24% for 2001 and 17% for 2000. The earnings

effect from differences between actual and projected pension benefit income was based on any earnings sharing mechanisms approved by state utility commissions.

Other (income) decreased $8 million in 2002 primarily due to a decrease in miscellaneous income of $6 million, and decreased $14 million in 2001 primarily due to an $18 million decrease in interest income largely due to funds used to finance the company's merger transactions in 2000. Other deductions increased $10 million in 2002 primarily due to NYSEG's $16 million loss on early retirement of debt and were unchanged in 2001. (See Financing Activities and Note 1 to the Consolidated Financial Statements.)

Interest charges increased $41 million in 2002 including $34 million because of the addition of RGS Energy 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. Interest charges increased $65 million in 2001 due to a $32 million increase for additional borrowings to finance the company's merger transactions, including the RGS Energy merger, and a $32 million increase for interest charges due to the acquisitions of CNE, CMP Group, CTG Resources and Berkshire Energy in 2000.

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 RGS Energy. Preferred stock dividends increased $13 million in 2001 due to the company's issuance of trust preferred securities in July 2001.

The effective tax rate was 31% in 2002 and 43% in 2001. The decrease is the result of various items 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) | **2002** | 2001 | 2000 | 2002 over 2001 Change | 2001 over 2000 Change |
|---|---|---|---|---|---|
| Deliveries – Megawatt-hours | | | | | |
| Retail | **26,869** | 23,238 | 17,133 | 16% | 36% |
| Wholesale | **5,330** | 6,048 | 6,214 | (12%) | (3%) |
| Operating Revenues | **$2,568,247** | $2,504,896 | $2,023,610 | 3% | 24% |
| Operating Expenses | **$2,119,218** | $1,951,475 | $1,540,953 | 9% | 27% |
| Operating Income | **$449,029** | $553,421 | $482,657 | (19%) | 15% |

**Operating Revenues** > The $63 million increase in operating revenues for 2002 is primarily due to the addition of RG&E's 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 a reduction of $138 million because CMP is no longer the standard-offer provider for the supply of electricity effective in March 2002; $114 million due to a rate reduction for NYSEG, effective March 1, 2002; and lower wholesale revenues of $64 million primarily due to lower market prices for electricity.

Operating revenues for 2001 increased $481 million compared to 2000 primarily due to the first full year of CMP's delivery revenues, which added $565 million, and amortization of deferred gains of $9 million. Those increases were partially offset by $37 million due to lower wholesale deliveries because of warmer weather, $32 million as a result of CMP no longer collecting revenue for the supply of electricity to certain retail customers and $22 million due to reduced transmission revenues.



**Operating Expenses** > Operating expenses for 2002 increased $168 million. The increase in operating expenses for 2002 was $131 million excluding $25 million for restructuring expenses in 2002 and $12 million for the effect of the sale of NYSEG's share of NMP2 in 2001. That increase includes $291 million for the addition of RG&E's

operating 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; and $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. 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 expenses for 2001 increased $411 million. The increase in operating expenses for 2001 was $423 million, excluding $12 million for the effect of the sale of NYSEG's share of NMP2, primarily due to the first full year of CMP's operating costs of $490 million. That increase was partially offset by $31 million because of lower purchased power costs primarily due to lower deliveries, $17 million for lower electricity supply costs because CMP no longer supplies electricity unless directed to by the MPUC, and $18 million due to cost control efforts relating to retirement benefits and compensation.

## Operating Results for the Natural Gas Delivery Business

| (Thousands) | **2002** | 2001 | 2000 | 2002 over 2001 Change | 2001 over 2000 Change |
|---|---|---|---|---|---|
| Deliveries – Dekatherms | | | | | |
| Retail | **181,859** | 148,000 | 108,139 | 23% | 37% |
| Wholesale | **7,074** | 9,298 | 10,674 | (24%) | (13%) |
| Operating Revenues | **$1,032,539** | $1,026,124 | $772,131 | 1% | 33% |
| Operating Expenses | **$882,883** | $936,606 | $699,402 | (6%) | 34% |
| Operating Income | **$149,656** | $89,518 | $72,729 | 67% | 23% |

**Operating Revenues** > Operating revenues increased $6 million for 2002. Operating revenues increased $126 million due to the addition of RG&E's 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 are passed on to customers and a $30 million decrease due to fewer wholesale customers.

For 2001, operating revenues increased $254 million primarily due to the first full year of revenues from SCG – $69 million, CNG – $245 million and Berkshire Gas – $45 million. Recovery of natural gas costs primarily from nonresidential deliveries also added $27 million to revenues. Those increases were partially offset by $116 million due to lower deliveries because of warmer weather and $11 million due to lower natural gas prices for wholesale sales.

**Operating Expenses** > Operating expenses decreased $54 million for 2002. The decrease in operating expenses for 2002 was $69 million excluding $15 million for restructuring expenses. 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 $115 million for the addition of RG&E's operating 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.

Operating expenses for 2001 increased $237 million primarily due to the first full year of natural gas purchases and operating costs for SCG – $58 million, CNG – $218 million and Berkshire Gas – $41 million. Those increases were partially offset by $60 million of reduced purchased natural gas costs due to lower prices and deliveries and $13 million for cost control efforts relating to retirement benefits and compensation.

# Consolidated Balance Sheets

| December 31 | 2002 | 2001 |
|---|---|---|
| (Thousands) | | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | **$250,490** | $437,014 |
| Special deposits | **47,643** | 1,555 |
| Accounts receivable, net | **737,876** | 564,671 |
| Note receivable | **380** | 12,126 |
| Fuel, at average cost | **117,678** | 92,234 |
| Materials and supplies, at average cost | **22,953** | 21,466 |
| Accumulated deferred income tax benefits, net | **8,697** | 4,170 |
| Prepayments and other current assets | **85,787** | 41,600 |
| **Total Current Assets** | **1,271,504** | 1,174,836 |
| **Utility Plant, at Original Cost** | | |
| Electric | **5,787,762** | 3,874,972 |
| Natural gas | **2,347,011** | 1,771,636 |
| Common | **360,776** | 213,362 |
| | **8,495,549** | 5,859,970 |
| Less accumulated depreciation | **3,873,267** | 2,270,516 |
| **Net Utility Plant in Service** | **4,622,282** | 3,589,454 |
| Construction work in progress | **179,557** | 36,978 |
| **Total Utility Plant** | **4,801,839** | 3,626,432 |
| **Other Property and Investments, Net** | **452,710** | 216,556 |
| **Regulatory and Other Assets** | | |
| Regulatory assets | | |
| Nuclear plant obligations | **524,679** | 199,797 |
| Unfunded future income taxes | **208,164** | 164,657 |
| Unamortized loss on debt reacquisitions | **45,353** | 53,965 |
| Demand-side management program costs | **8,394** | 18,137 |
| Environmental remediation costs | **106,262** | 85,835 |
| Nonutility generator termination agreements | **168,014** | 9,480 |
| Other | **361,960** | 239,258 |
| Total regulatory assets | **1,422,826** | 771,129 |
| Other assets | | |
| Goodwill, net | **1,518,173** | 897,807 |
| Prepaid pension benefits | **540,426** | 435,901 |
| Other | **262,401** | 146,571 |
| Total other assets | **2,321,000** | 1,480,279 |
| **Total Regulatory and Other Assets** | **3,743,826** | 2,251,408 |
| **Total Assets** | **$10,269,879** | $7,269,232 |

The notes on pages 41 through 61 are an integral part of the financial statements.

# Consolidated Balance Sheets

| December 31 | 2002 | 2001 |
|---|---|---|
| (Thousands) | | |
| **Liabilities** | | |
| **Current Liabilities** | | |
| Current portion of long-term debt | **$545,404** | $225,678 |
| Notes payable | **322,200** | 173,383 |
| Accounts payable and accrued liabilities | **361,499** | 224,150 |
| Interest accrued | **44,310** | 36,183 |
| Taxes accrued | **30,036** | 7,020 |
| Other | **200,927** | 142,926 |
| **Total Current Liabilities** | **1,504,376** | 809,340 |
| **Regulatory and Other Liabilities** | | |
| Regulatory liabilities | | |
| Deferred income taxes | **203,926** | 157,196 |
| Gain on sale of generation assets | **126,325** | 251,254 |
| Pension benefits | **67,205** | 52,642 |
| Other | **104,937** | 68,879 |
| Total regulatory liabilities | **502,393** | 529,971 |
| Other liabilities | | |
| Deferred income taxes | **702,426** | 461,600 |
| Nuclear plant obligations | **314,013** | 199,797 |
| Other postretirement benefits | **391,049** | 282,791 |
| Environmental remediation costs | **133,933** | 102,930 |
| Other | **448,156** | 241,975 |
| Total other liabilities | **1,989,577** | 1,289,093 |
| **Total Regulatory and Other Liabilities** | **2,491,970** | 1,819,064 |
| Long-term debt | **3,351,959** | 2,471,278 |
| **Total Liabilities** | **7,348,305** | 5,099,682 |
| **Commitments** | **-** | - |
| **Preferred Stock of Subsidiaries** | | |
| Company-obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures | **345,000** | 345,000 |
| Redeemable solely at the option of subsidiaries | **90,962** | 43,373 |
| Subject to mandatory redemption requirements | **25,000** | - |
| **Common Stock Equity** | | |
| Common stock ($.01 par value, 300,000 shares authorized, 144,966 shares outstanding at December 31, 2002, and 116,718 shares outstanding at December 31, 2001) | **1,455** | 1,182 |
| Capital in excess of par value | **1,447,664** | 842,989 |
| Retained earnings | **1,061,428** | 998,281 |
| Accumulated other comprehensive income (loss) | **(34,167)** | (22,335) |
| Treasury stock, at cost (574 shares at December 31, 2002 and 1,418 shares at December 31, 2001) | **(15,768)** | (38,940) |
| **Total Common Stock Equity** | **2,460,612** | 1,781,177 |
| **Total Liabilities and Stockholders' Equity** | **$10,269,879** | $7,269,232 |

The notes on pages 41 through 61 are an integral part of the financial statements.

# Consolidated Statements of Income

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands, except per share amounts) | | | |
| **Operating Revenues** | | | |
| Sales and services | **$4,008,918** | $3,759,787 | $2,959,520 |
| **Operating Expenses** | | | |
| Electricity purchased and fuel used in generation | **1,276,087** | 1,334,507 | 1,073,728 |
| Natural gas purchased | **603,258** | 694,038 | 496,509 |
| Gasoline, propane and oil purchased | **143,770** | 3,688 | 1,560 |
| Other operating expenses | **713,384** | 566,498 | 434,405 |
| Maintenance | **162,122** | 139,395 | 108,106 |
| Depreciation and amortization | **246,996** | 204,281 | 165,524 |
| Other taxes | **230,558** | 192,772 | 165,767 |
| Restructuring expenses | **40,567** | – | – |
| Gain on sale of generation assets | **–** | (84,083) | – |
| Deferral of asset sale gain | **–** | 71,803 | – |
| **Total Operating Expenses** | **3,416,742** | 3,122,899 | 2,445,599 |
| **Operating Income** | **592,176** | 636,888 | 513,921 |
| **Writedown of Investment** | **12,209** | 78,422 | – |
| **Other (Income)** | **(26,883)** | (35,257) | (49,671) |
| **Other Deductions** | **29,847** | 20,216 | 19,514 |
| **Interest Charges, Net** | **257,747** | 217,066 | 152,520 |
| **Preferred Stock Dividends of Subsidiaries** | **32,129** | 14,455 | 963 |
| **Income Before Income Taxes** | **287,127** | 341,986 | 390,595 |
| **Income Taxes** | **98,524** | 154,379 | 155,561 |
| **Net Income** | **$188,603** | $187,607 | $235,034 |
| **Earnings Per Share, basic and diluted** | **$1.44** | $1.61 | $2.06 |
| **Average Common Shares Outstanding** | **131,117** | 116,708 | 114,213 |

The notes on pages 41 through 61 are an integral part of the financial statements.

# Consolidated Statements of Cash Flows

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| **Operating Activities** | | | |
| Net income | **$188,603** | $187,607 | $235,034 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation and amortization | **255,782** | 247,847 | 228,543 |
| Income taxes and investment tax credits deferred, net | **43,564** | 4,588 | 29,114 |
| Restructuring expenses | **40,567** | – | – |
| Gain on sale of generation assets | **-** | (84,083) | – |
| Deferral of asset sale gain | **-** | 71,803 | – |
| Pension income | **(70,189)** | (76,229) | (67,849) |
| Writedown of investment | **12,209** | 78,422 | – |
| Changes in current operating assets and liabilities | | | |
| Accounts receivable, net | **(24,247)** | 125,121 | (83,688) |
| Sale of accounts receivable program | **-** | (152,000) | – |
| Inventory | **6,111** | (25,445) | (13,623) |
| Prepayments and other current assets | **(3,998)** | 3,119 | (1,341) |
| Accounts payable and accrued liabilities | **5,551** | (123,832) | (10,289) |
| Interest accrued | **(3,118)** | 874 | 8,097 |
| Taxes accrued | **4,895** | 1,125 | 2,897 |
| Other current liabilities | **4,089** | (53,372) | (11,994) |
| Other assets | **(66,279)** | (44,163) | (68,889) |
| Other liabilities | **16,896** | (6,848) | 12,210 |
| **Net Cash Provided by Operating Activities** | **410,436** | 154,534 | 258,222 |
| **Investing Activities** | | | |
| Acquisitions, net of cash acquired | **(681,397)** | – | (1,442,717) |
| Utility plant additions | **(224,450)** | (208,677) | (154,009) |
| Sale of generation assets | **59,442** | 59,441 | – |
| Temporary investments | **-** | – | 1,017,249 |
| Other property and investments additions | **(29,177)** | (30,271) | (48,143) |
| Other property and investments sold | **12,138** | 18,967 | 32,946 |
| Special deposits | **(5,166)** | 19,909 | (21,954) |
| Other | **1,490** | (19,344) | 11,002 |
| **Net Cash Used in Investing Activities** | **(867,120)** | (159,975) | (605,626) |
| **Financing Activities** | | | |
| Issuance of common stock | **17,844** | 7,201 | – |
| Repurchase of common stock | **(2,139)** | (24,116) | (163,493) |
| Issuance of mandatorily redeemable trust preferred securities | **-** | 345,000 | – |
| Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums | **(435,720)** | (1,890) | (134,947) |
| Long-term note issuances | **767,807** | 355,553 | 601,095 |
| Long-term note repayments | **(97,124)** | (29,965) | (20,771) |
| Notes payable three months or less, net | **166,702** | (269,012) | 183,866 |
| Notes payable issuances | **28,400** | 54,445 | 16,345 |
| Notes payable repayments | **(50,154)** | (31,045) | (8,265) |
| Dividends on common stock | **(125,456)** | (107,342) | (99,606) |
| **Net Cash Provided by Financing Activities** | **270,160** | 298,829 | 374,224 |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | **(186,524)** | 293,388 | 26,820 |
| **Cash and Cash Equivalents, Beginning of Year** | **437,014** | 143,626 | 116,806 |
| **Cash and Cash Equivalents, End of Year** | **$250,490** | $437,014 | $143,626 |

The notes on pages 41 through 61 are an integral part of the financial statements.

# 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) | Treasury Stock | Total |
|---|---|---|---|---|---|---|---|
| **Balance, January 1, 2000** | 109,343 | $1,108 | $660,936 | $782,588 | $(1,681) | $(38,997) | $1,403,954 |
| Net income | | | | 235,034 | | | 235,034 |
| Other comprehensive income, net of tax | | | | | (33,142) | | (33,142) |
| Comprehensive income | | | | | | | 201,892 |
| Common stock dividends declared ($.88 per share) | | | | (99,606) | | | (99,606) |
| Common stock issued – merger transactions | 16,269 | 163 | 373,545 | | | | 373,708 |
| Common stock repurchased | (7,958) | (80) | (163,413) | | | | (163,493) |
| Treasury stock transactions, net | 2 | | (8) | | | 57 | 49 |
| Amortization of capital stock issue expense | | | 18 | | | | 18 |
| **Balance, December 31, 2000** | 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 |

The notes on pages 41 through 61 are an integral part of the financial statements.

# Notes to Consolidated 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. – Central Maine Power Company (CMP); Connecticut Energy Corporation (CNE) – The Southern Connecticut Gas Company (SCG); CTG Resources, Inc. – 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 $237 million at December 31, 2002, and $143 million at December 31, 2001, and are shown net of an allowance for doubtful accounts of $59 million at December 31, 2002, and $18 million at December 31, 2001. Bad debt expense was $46 million in 2002, $34 million in 2001 and $24 million in 2000. Bad debt expense for 2002 includes RGS Energy beginning July 1, 2002, and for 2001 includes CNE, CMP Group, CTG Resources and Berkshire Energy for a full year for the first time.

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 on the consolidated statements of income and were approximately $3 million. Fees related to the sale of accounts receivable through March 31, 2001, are included in other deductions on the consolidated statements of income and amounted to approximately $2 million in 2001 and $10 million in 2000. 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 period. The weighted-average common shares outstanding for diluted EPS include the incremental effect of stock options issued and exclude stock options issued in tandem with stock appreciation rights (SARs). 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 diluted EPS for each period follows:

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| **Numerator** | | | |
| Net income | **$188,603** | $187,607 | $235,034 |
| **Denominator** | | | |
| Basic average common shares outstanding | **131,117** | 116,708 | 114,213 |
| Potentially dilutive common shares | **215** | 198 | 170 |
| Options issued with SARs | **(215)** | (198) | (170) |
| Dilutive average common shares | **131,117** | 116,708 | 114,213 |
| **Earnings per Share, basic** | **$1.44** | $1.61 | $2.06 |
| **Earnings per Share, diluted** | **$1.44** | $1.61 | $2.06 |

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: 4.7 million in 2002, 2.1 million in 2001 and 1.9 million in 2000.

**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. Those investments are included in cash and cash equivalents on the consolidated balance sheets.

| **Supplemental Disclosure of Cash Flows Information** | **2002** | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| Cash paid during the year ended December 31: | | | |
| Interest, net of amounts capitalized | **$238,305** | $208,431 | $132,009 |
| Income taxes, net of benefits received | **$54,418** | $113,274 | $154,108 |
| Acquisitions: | | | |
| Fair value of assets acquired | **$3,264,093** | – | $2,526,971 |
| Liabilities assumed | **(1,826,528)** | – | (651,589) |
| Preferred stock of subsidiaries | **(72,000)** | – | (37,591) |
| Common stock issued | **(612,082)** | – | (373,708) |
| Cash acquired | **(72,086)** | – | (21,366) |
| Net cash paid for acquisitions | **$681,397** | – | $1,442,717 |

**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 includes estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property – 51 years, distribution property – 42 years, generation property – 41 years, gas production property – 26 years, gas storage property – 24 years and other property – 28 years. The company's depreciation accruals were equivalent to 3.5% of average depreciable property for 2002, 3.1% for 2001 and 3.1% for 2000, which was weighted for the effect of the mergers completed in June 2002 and September 2000.

**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 and goodwill was amortized on a straight-line basis over five to 40 years until December 31, 2001. Beginning in 2002, 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 impairments would be recognized when the fair value of goodwill is less than its carrying value. (See Note 4.)

**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 have paid if a separate income tax return had been 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 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| Dividends | **$(233)** | $(1,844) | $(44) |
| Interest income | **(13,213)** | (13,125) | (31,233) |
| Noncash returns | **(6,693)** | (2,404) | (1,360) |
| Allowance for funds used during construction | **(1,401)** | (652) | (713) |
| Gain from sale of nonutility property | **(231)** | (3,628) | – |
| Earnings from equity investments | **(4,631)** | (7,162) | (2,232) |
| Miscellaneous | **(481)** | (6,442) | (14,089) |
| **Total other (income)** | **$(26,883)** | $(35,257) | $(49,671) |
| NYSEG early retirement of debt | **$16,145** | – | $2,766 |
| Fees on sale of accounts receivable | **–** | $2,495 | 10,368 |
| Miscellaneous | **13,702** | 17,721 | 6,380 |
| **Total other deductions** | **$29,847** | $20,216 | $19,514 |

**Principles of consolidation >** These financial statements consolidate the company's majority-owned subsidiaries after eliminating intercompany transactions.

**Reclassifications >** Certain amounts have been reclassified on the consolidated financial statements to conform with the 2002 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 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 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 March 1, 2002, through February 28, 2005.

NYSEG and RG&E enter into power purchase and sales transactions with the NYISO. When sales of owned generation are 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 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 to manage fluctuations in natural gas commodity prices and provide price stability to customers. The cost or benefit of natural gas futures 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, financial electricity contracts and interest rate agreements as assets or liabilities on the consolidated balance sheets. The company's derivative asset was $80 million at December 31, 2002, and its derivative liability was $9 million at December 31, 2002, and $32 million at December 31, 2001. 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 in the consolidated statements of income. Changes in the fair value of the interest rate swap agreement are recorded 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, 2002, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted transactions is 84 months. The company estimates that gains of $16 million will be reclassified from accumulated other comprehensive income into earnings in 2003, 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 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 adopted Statement 143 as of January 1, 2003. The company recognized an asset retirement obligation of approximately $415 million, a regulatory asset of $141 million, a regulatory liability of $5 million, an increase in utility plant of $74 million and a decrease in accumulated depreciation of $205 million. There was no effect on net income. Previously the company had recognized $266 million of the obligation as accumulated depreciation.

**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 and the cost of removal less salvage are charged to accumulated depreciation.

## NOTE 2 Restructuring

In the fourth quarter of 2002 the company recorded $41 million of restructuring expenses, including $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 are $20 million for a voluntary early retirement program that will be paid from the companies' pension plans and $3 million for an involuntary severance program, primarily for salaried employees of the company's six operating utilities, and $1 million for other associated costs.

Those programs are expected to result in a decline in overall employee headcount of approximately 650, or 8%, by April 30, 2003. That includes approximately 70 from CMP, 260 from NYSEG, 245 from RG&E and 75 from Berkshire Gas, CNG and SCG. The employees affected by the involuntary severance program were notified in January 2003.

## NOTE 3 Acquisition of RGS Energy Group

On June 28, 2002, the company acquired all of the outstanding common stock of RGS Energy for a combination of cash and Energy East common stock. The company's consolidated statements of income and cash flows include RGS Energy's results of operations beginning with July 2002. RGS Energy, through its regulated subsidiary RG&E, engages in generating, purchasing and delivering electricity and purchasing and delivering natural gas in an area centered around the city of Rochester, New York. Through its unregulated subsidiary, Energetix, Inc., RGS Energy engages in retail electric, natural gas and liquid fuel businesses throughout upstate New York. In connection with Energy East's merger with RGS Energy, NYSEG became a wholly-owned subsidiary of RGS Energy.

Under the merger agreement 45% of the RGS Energy common stock, 15.6 million shares, was converted into 27.5 million shares of Energy East common stock valued at $612 million. The value of the shares issued was determined based on the market price of Energy East's stock at the end of the day on June 27, 2002. The remaining 55% of the RGS Energy common stock was exchanged for $753 million in cash ($39.50 per RGS Energy share). The purchase price was about $1.4 billion, which includes $11 million of merger-related costs.

The following table summarizes the components of the purchase price and preliminary allocation of the purchase price to the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition. RGS Energy did not push goodwill down to its subsidiaries. As of December 31, 2002, $29 million was allocated to intangible assets based on a preliminary appraisal. The allocation of the purchase price will be adjusted when final appraisals are received, RG&E's electric and gas rate cases are finalized and actual amounts for estimated liabilities become known.

**Calculation of the purchase price for assets acquired**

| (Thousands) | |
|---|---|
| Cash paid for stock purchased | $753,483 |
| Common stock issued | 612,082 |
| Merger-related fees and expenses | 11,000 |
| **Total purchase price for common equity** | **1,376,565** |
| Plus fair market value of liabilities and preferred stock assumed | |
| Current and other liabilities | 883,502 |
| Long-term debt | 932,026 |
| Preferred stock | 72,000 |
| **Total liabilities and preferred stock** | **1,887,528** |
| **Total purchase price for assets acquired** | **$3,264,093** |
| Allocation of purchase price for assets acquired | |
| Property, plant and equipment | $1,203,282 |
| Goodwill | 622,342 |
| Intangible assets subject to amortization | 22,019 |
| Intangible assets not amortized | 6,600 |
| All other assets, including working capital | 1,409,850 |
| **Total** | **$3,264,093** |

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 | **$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 4 Goodwill and Other Intangible Assets

Effective January 1, 2002, the company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets. As required by Statement 142 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 (amortized intangible assets) and are reviewed for impairment.

The company determined that there was no impairment of goodwill as of January 1, 2002. There was no reclassification of goodwill to intangible assets and no reclassification of intangible assets to goodwill as of January 1, 2002. Annual impairment testing was also completed and it was determined that there was no impairment of goodwill or unamortized intangible assets for the companies at September 30, 2002.

The changes in the carrying amount of goodwill on the company's balance sheets, by operating segment, for the year ended December 31, 2002, are:

| | Electric Delivery | Natural Gas Delivery | Other | Total |
|---|---|---|---|---|
| (Thousands) | | | | |
| Balance, January 1, 2002 | $325,174 | $554,787 | $17,846 | $897,807 |
| Goodwill acquired during the year | 494,063 | 123,516 | 4,763 | 622,342 |
| Goodwill written off related to sale of business | – | – | (1,709) | (1,709) |
| Other adjustments | 406 | (653) | (20) | (267) |
| Balance, December 31, 2002 | $819,643 | $677,650 | $20,880 | $1,518,173 |

**Other Intangible Assets** > At December 31, 2002, the company's unamortized intangible assets had a carrying amount of $14 million and primarily consisted of trade names and pension assets. At December 31, 2001, the company's unamortized intangible assets had a carrying amount of $4 million and primarily consisted of pension assets. At December 31, 2002, the company's amortized intangible assets had a gross carrying amount of $47 million and primarily consisted of customer lists and investments in pipelines. Customer lists acquired in 2002 with a carrying amount of $14 million will be amortized over three to 10 years. At December 31, 2001, the company's amortized intangible assets had a gross carrying amount of $26 million and primarily consisted of investments in pipelines. Accumulated amortization was $15 million at December 31, 2002, and $5 million at December 31, 2001.

Estimated amortization expense for intangible assets for the next five years (in thousands) is:

| 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| $4,362 | $4,285 | $3,512 | $2,723 | $2,667 |

**Transitional Information** > Results of operations information for the company as though goodwill had been accounted for under Statement 142 for all years presented is:

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands, except per share data) | | | |
| Reported net income | $188,603 | $187,607 | $235,034 |
| Add back: goodwill amortization | – | 25,379 | 18,486 |
| Adjusted net income | $188,603 | $212,986 | $253,520 |
| Reported basic and diluted earnings per share | $1.44 | $1.61 | $2.06 |
| Add back: goodwill amortization | – | .22 | .16 |
| Adjusted basic and diluted earnings per share | $1.44 | $1.83 | $2.22 |

## NOTE 5 Income Taxes

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| Current | **$50,663** | $147,497 | $129,220 |
| Deferred, net | | | |
| Accelerated depreciation | **19,258** | 12,312 | 628 |
| Pension benefits | **36,932** | 30,430 | 24,051 |
| Statement 106 postretirement benefits | **(4,627)** | (4,079) | (11,417) |
| Demand-side management | **(2,189)** | (9,295) | (8,335) |
| Asset sale gain account amortization | **29,367** | – | – |
| Restructuring expenses | **(15,816)** | – | – |
| Miscellaneous | **(12,540)** | (20,371) | 23,676 |
| ITC | **(2,524)** | (2,115) | (2,262) |
| **Total** | **$98,524** | $154,379 | $155,561 |

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

| Year Ended December 31 | 2002 | 2001 | 2000 |
|---|---|---|---|
| (Thousands) | | | |
| Tax expense at statutory rate | **$111,740** | $124,754 | $137,045 |
| Depreciation and amortization not normalized | **5,125** | 26,373 | 8,032 |
| ITC amortization | **(2,524)** | (2,115) | (2,262) |
| Trust preferred securities | **(9,932)** | (4,389) | – |
| State taxes, net of federal benefit | **9,724** | 14,692 | 21,386 |
| Other, net | **(15,609)** | (4,936) | (8,640) |
| **Total** | **$98,524** | $154,379 | $155,561 |

The effective tax rate was 31% in 2002 and 43% in 2001. The decrease is the result of various items 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 | 2002 | 2001 |
|---|---|---|
| (Thousands) | | |
| **Current Deferred Tax Assets** | **$8,697** | $4,170 |
| **Noncurrent Deferred Tax Liabilities** | | |
| Depreciation | **$750,739** | $573,071 |
| Unfunded future income taxes | **129,481** | 80,125 |
| Accumulated deferred ITC | **45,039** | 29,370 |
| Deferred gain on sale of generation assets | **63,969** | (109,246) |
| Pension benefits | **87,717** | 102,109 |
| Statement 106 postretirement benefits | **(92,182)** | (64,013) |
| Nuclear decommissioning | **(44,093)** | – |
| Other | **(34,318)** | 7,380 |
| **Total Noncurrent Deferred Tax Liabilities** | **$906,352** | 618,796 |
| Less amounts classified as regulatory liabilities | | |
| Deferred income taxes | **203,926** | 157,196 |
| **Noncurrent Deferred Income Taxes** | **$702,426** | $461,600 |

Energy East and its subsidiaries have no federal tax credit or loss carryforwards, nor do they have any valuation allowances.

## NOTE 6 Long-term Debt

At December 31, 2002 and 2001, the company's consolidated long-term debt was:

| | Maturity Dates | Interest Rates | Amount 2002 | 2001 |
|---|---|---|---|---|
| (Thousands) | | | | |
| First mortgage bonds[1] | 2003 to 2032 | 5.84% to 10.06% | **$890,500** | $609,840 |
| Pollution control notes – fixed | 2006 to 2034 | 5 3/8% to 6.15% | **351,000** | 325,500 |
| Pollution control notes – variable | 2015 to 2032 | 0.75% to 4.43% | **408,900** | 307,000 |
| Various long-term debt[2] | 2003 to 2030 | 0.95% to 10.48% | **1,924,130** | 1,137,809 |
| Putable asset term securities[3] | 2033 | 7.75% | **300,000** | 300,000 |
| Obligations under capital leases | | | **34,447** | 36,960 |
| Unamortized premium and discount on debt, net | | | **(11,614)** | (20,153) |
| | | | **3,897,363** | 2,696,956 |
| Less debt due within one year – included in current liabilities | | | **545,404** | 225,678 |
| **Total** | | | **$3,351,959** | $2,471,278 |

At December 31, 2002, long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years are:

| 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|
| $545,404 | $43,839 | $61,611 | $341,157 | $232,750 |

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, in addition to the information provided for CMP, NYSEG and RG&E below, Berkshire Gas and SCG have first mortgage bonds that are secured by liens on substantially all of their respective utility properties. Berkshire Gas has other long-term debt that is secured by its properties, and 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's first mortgage bonds, totaling $150 million at December 31, 2002, are secured by a first mortgage lien on substantially all of its properties. NYSEG has no other secured indebtedness. None of NYSEG's other debt obligations are guaranteed or secured by any of its affiliates.

RG&E's first mortgage bonds, totaling $705.5 million at December 31, 2002, are secured by a first mortgage lien on substantially all of its properties. Other than the promissory note described below, RG&E has no other secured indebtedness. None of RG&E's other debt obligations are guaranteed or secured by any of its affiliates.

(2) Includes RG&E's promissory note in connection with the Kamine Global Settlement Agreement, collateralized by a mortgage, the lien for which is subordinate to the first mortgage lien. On January 9, 2003, RG&E paid off the remaining $80 million balance of this note that was due to mature in 2014.

(3) The Putable Asset Term Securities bear interest at 7.75% until November 15, 2003, and then, as provided by an agreement, will either be redeemed by the company or will bear interest at a fixed or floating rate until November 15, 2033, unless extended to November 15, 2034. At December 31, 2002, $300 million of Putable Asset Term Securities were classified as current portion of long-term debt as a result of this provision.

**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.

In the event of a cross-default of other long-term debt obligations of CMP, The Finance Authority of Maine, under a Loan Agreement, may declare an amount equal to the unpaid principal amount, currently less than $10 million, and interest accrued immediately due and payable.

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 7 Bank Loans and Other Borrowings

The company and its subsidiaries have credit agreements with various expiration dates in 2003 and 2005 and pay fees in lieu of compensating balances in connection with the credit agreements. The agreements provided for maximum borrowings of $755 million at December 31, 2002 and 2001.

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 $322 million of such short-term debt outstanding at December 31, 2002, and $173 million outstanding at December 31, 2001. The weighted-average interest rate on short-term debt was 2.1% at December 31, 2002, and 2.6% at December 31, 2001.

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 was 0.59 to 1.00 at December 31, 2002.

In its revolving credit facility, which is 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 stockholders 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, 2002, CMP's consolidated total debt ratio was 33.6% and its interest coverage ratio was 3.73 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, 2002, the ratio of earnings before interest expense and income tax to interest expense was 3.4 to 1.0 for NYSEG and 2.3 to 1.0 for RG&E. At December 31, 2002, the ratio of total indebtedness to total capitalization was 0.53 to 1.00 for NYSEG and 0.52 to 1.00 for RG&E.



NYSEG has two letters of credit and reimbursement agreements 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, 2002.

## NOTE 8 Preferred Stock of Subsidiaries

**Trust preferred securities** > The company-obligated mandatorily redeemable trust preferred securities are 8 1/4% Capital Securities issued by Energy East Capital Trust I, a Delaware business trust that is a wholly-owned finance subsidiary of the company. The assets of the trust consist solely of the company's 8 1/4% junior subordinated debt securities maturing on July 31, 2031. The company has fully and unconditionally guaranteed the trust's payment obligations with respect to the Capital Securities.

At December 31, 2002 and 2001, the consolidated preferred stock was:

| Series | Par Value Per Share | Redemption Price Per Share | Shares Authorized and Outstanding(1) | Amount (Thousands) 2002 | 2001 |
|---|---|---|---|---|---|
| Redeemable solely at the option of subsidiaries: | | | | | |
| 3.50% | $100 | $101.00 | 220,000 | **$22,000** | $22,000 |
| 3.75% | 100 | 104.00 | 78,379 | **7,838** | 7,838 |
| 4% F | 100 | 105.00 | 120,000 | **12,000** | – |
| 4.10% H | 100 | 101.00 | 80,000 | **8,000** | – |
| 4.10% J | 100 | 102.50 | 50,000 | **5,000** | – |
| 4.15% (1954) | 100 | 102.00 | 4,317 | **432** | 432 |
| 4.40% | 100 | 102.00 | 7,093 | **709** | 709 |
| 4 1/2% (1949) | 100 | 103.75 | 11,800 | **1,180** | 1,180 |
| 4.55% M | 100 | 101.00 | 100,000 | **10,000** | – |
| 4.60% | 100 | 101.00 | 30,000 | **3,000** | 3,000 |
| 4.75% | 100 | 101.00 | 50,000 | **5,000** | 5,000 |
| 4.75% I | 100 | 101.00 | 60,000 | **6,000** | – |
| 4.80% | 100 | 100.00 | 2,574 | **257** | 259 |
| 4.95% K | 100 | 102.00 | 60,000 | **6,000** | – |
| 5.25% | 100 | 102.00 | 50,000 | **5,000** | 5,000 |
| 6% Noncallable | 100 | – | 5,180 | **518** | 518 |
| 6.00% | 100 | 110.00 | 4,104 | **411** | 413 |
| 8.00% Noncallable | 3.125 | – | 108,843 | **340** | 340 |
| Preferred stock issuance costs | | | | **(2,723)** | (3,316) |
| **Total** | | | | **$90,962** | $43,373 |
| Subject to mandatory redemption requirements: | | | | | |
| 6.60% V(2) | $100 | $100.00 | 250,000 | **$25,000** | – |

(1) At December 31, 2002, 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, 775,472 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.

(2) This RG&E 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.

The company's subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2000 through 2002:

| Subsidiary Company | Date | Series | Amount |
|---|---|---|---|
| CMP | October 1, 2000 | 7.999% | $9.9 million * |
| CNG | September 26, 2000 | 8.00 % | $3,250 * |
| CNG | Various 2001 | 6.00 % | $45,900 * |
| CNG | Various 2001 | 8.00 % | $41,222 ** |
| CNG | June 7, 2002 | 6.00 % | $2,500 * |
| Berkshire | September 30, 2001 | 4.80 % | $41,000 * |
| Berkshire | September 30, 2002 | 4.80 % | $1,500 * |

*Redeemed **Substantially all purchased at a premium

**Voting rights of preferred shares issued by subsidiaries >**

***Trust preferred securities*** – Holders of trust preferred securities have no voting rights, except that they may vote on certain transactions if such transaction would cause Energy East Capital Trust I or a successor entity to be classified other than as a grantor trust for U.S. federal income tax purposes, and they may vote on certain matters affecting the powers, preferences or special rights of the trust preferred securities.

***Preferred stock redeemable solely at the option of subsidiaries*** – 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 9 Commitments

**Capital spending >** The company has commitments in connection with its capital spending program. Capital spending is projected to be $338 million in 2003, which includes RGS Energy and 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 $611 million for NUG power in 2002, $593 million in 2001 and $439 million in 2000 (CMP beginning on September 1, 2000, the date it was acquired). CMP and NYSEG estimate that their combined NUG power purchases will total $613 million in 2003, $632 million in 2004, $642 million in 2005, $578 million in 2006 and $544 million in 2007.

## NOTE 10 Jointly-Owned Generation Assets and Nuclear Generation Insurance and Decommissioning

**Cayuga Energy, Inc.** > Cayuga Energy, Inc. owns an 85% interest in South Glens Falls Energy, L.L.C., 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, L.L.C., 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.

On July 31, 2002, Vermont Yankee Nuclear Power Corporation sold the Vermont Yankee nuclear power plant, including CMP's 4% ownership interest, to Entergy Corporation. Any benefits realized from the sale, which are expected to be less than $1 million, will be 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 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*** - For its 18% share of NMP2, NYSEG received at closing $59 million in cash and a $59 million 11% promissory note. On April 12, 2002, Constellation Nuclear paid the remaining balance plus accrued interest on the promissory note. 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 recorded expenses for electricity purchased in 2001 and 2002 in accordance with the agreement at the time the power was physically delivered, at prices pursuant to the agreement. The contract is not required to be marked-to-market and is not considered 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 NYSEG and RG&E additional revenue through 2021, which would mitigate increases in electricity prices. Both agreements are based on plant output. No amounts were recorded under the revenue sharing agreement in 2002 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 $9.5 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 $9.2 billion. Under the Price-Anderson Act, RG&E would be liable for up to $88 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 $3 million for accidental outage insurance.

**Nuclear plant decommissioning costs** > The estimated liability, in 2003 dollars, for decommissioning the various interests in nuclear plants, including spent fuel storage, is $387 million for CMP, which was updated in 2002 to include spent fuel storage and increases in projected costs, and $434 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 11 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, nine sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and seven of the 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 17 of the 19 sites. Remediation costs have been paid at the remaining two sites, and the company expects no additional liability to be incurred. An estimated liability of $5 million has been recorded related to 12 sites where the company believes it is probable that it will incur remediation costs, although it has not been notified that it is among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the 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 59 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, four sites are part of Maine's Voluntary Response Action Program and three of those four sites are part of Maine's Uncontrolled Sites Program, three sites are included in the Connecticut Inventory of Hazardous Waste Sites, and three sites are on the Massachusetts Department of Environmental Protection's list of confirmed disposal sites. The company has entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 39 of its 59 sites.

The company's estimate for all costs related to investigation and remediation of its 59 sites ranges from $126 million to $220 million at December 31, 2002. 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, reflected on the company's consolidated balance sheets was $126 million at December 31, 2002, and $101 million at December 31, 2001. The company recorded a corresponding regulatory asset, net of insurance recoveries, since it expects to recover the net costs in rates.

The company has reported petroleum spill incidents to the New York State Spill Incidents Report database and has recorded an estimated liability of $2 million to remediate these spill incidents.

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 12 Fair Value of Financial Instruments

The carrying amounts and estimated fair values of the company's financial instruments included on its consolidated balance sheets 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 | 2002 | 2002 | 2001 | 2001 |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| (Thousands) | | | | |
| *Investments – classified as* available-for-sale | **$296,425** | **$296,392** | $38,508 | $38,550 |
| First mortgage bonds | **$888,870** | **$973,232** | $606,112 | $623,055 |
| Pollution control notes – fixed | **$351,000** | **$364,865** | $325,500 | $333,056 |
| Pollution control notes – variable | **$408,900** | **$408,900** | $307,000 | $307,000 |
| Various long-term debt | **$1,915,160** | **$2,088,303** | $1,123,557 | $1,124,911 |
| Putable asset term securities | **$298,986** | **$335,288** | $297,827 | $310,017 |

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.

The company evaluated the carrying value of CMP Group's 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 of 2001 and the investment was written down to its fair market value of $12 million at September 30, 2001. 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 its investment in NEON. 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 five 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 of 2002, which was $1 million after taxes, or one 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 13 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 2002, 2001 and 2000 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 2000, 2001 and 2002 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 10 million shares authorized at December 31, 2002 and 2001, unoptioned shares totaled 1.9 million at December 31, 2002, and 4.5 million at December 31, 2001.

The company recorded compensation expense (benefit) for options/SARs of $12 million in 2002, less than $(1) million in 2001 and $(1) million in 2000.

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.

During 2000, 1,070,597 options/SARs were granted with a weighted-average exercise price equal to the weighted-average fair value of $23.06. 2,797 options with a weighted-average exercise price of $16.43 and 107,731 SARs with a weighted-average exercise price of $17.56 were exercised in 2000. 312,548 options/SARs with an exercise price of $23.99 were forfeited in 2000. The 2,925,379 options/SARs outstanding at December 31, 2000, had a weighted-average exercise price of $22.15. Of those outstanding at December 31, 2000, 197,309 options/SARs with exercise prices ranging from $10.88 to $14.69 and a weighted-average remaining life of six years had a weighted-average exercise price of $10.88 and 2,728,070 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 $22.97. Of those exercisable at December 31, 2000, 197,309 options/SARs with exercise prices ranging from $10.88 to $14.69 had a weighted-average price of $10.88 and 1,470,287 options/SARs with exercise prices ranging from $17.94 to $28.72 had a weighted-average exercise price of $22.98.

The company's Long-term Executive Incentive Share Plan provides participants cash awards if certain shareholder return criteria are achieved. There were 59,130 performance shares outstanding at December 31, 2002, and 95,418 performance shares outstanding at December 31, 2001. Compensation expense for 2002 was $0.4 million, there was no compensation expense for 2001 and compensation expense was $1 million for 2000. Beginning January 1, 2001, no new performance shares were granted under this plan (other than dividend performance shares). The plan will be eliminated in 2003.

## NOTE 14 Accumulated Other Comprehensive Income

| (Thousands) | Balance January 1 2000 | 2000 Change | Balance December 31 2000 | 2001 Change | Balance December 31 2001 | 2002 Change | Balance December 31 2002 |
|---|---|---|---|---|---|---|---|
| Foreign currency translation adjustment, net of income tax benefit of $ – for 2000, 2001 and 2002 | $(93) | $7 | $(86) | $86 | – | – | – |
| Unrealized gains (losses) on investments: | | | | | | | |
| Unrealized holding (losses) during period, net of income tax benefit of $23,804 for 2000, $7,980 for 2001 and $6,803 for 2002 | (1,588) | (32,519) | (34,107) | (10,400) | $(44,507) | $(9,654) | $(54,161) |
| 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 | 45,748 | 7,122 | 52,870 |
| Net unrealized gains (losses) on investments | (1,588) | (32,519) | (34,107) | 35,348 | 1,241 | (2,532) | (1,291) |
| Minimum pension liability adjustment, net of income tax benefit of $339 for 2000, $1,828 for 2001 and $39,378 for 2002 | – | (630) | (630) | (2,546) | (3,176) | (58,485) | (61,661) |
| 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 | 58,250 | – | 58,250 |
| Unrealized (losses) gains during period on derivatives qualified as hedges, net of tax benefit (expense) of $59,510 for 2001 and $(26,984) for 2002 | – | – | – | (89,955) | (89,955) | 37,692 | (52,263) |
| Reclassification adjustment for losses included in net income, net of income tax benefit of $(7,416) for 2001 and $(7,351) for 2002 | – | – | – | 11,305 | 11,305 | 11,493 | 22,798 |
| Net unrealized gains (losses) on derivatives qualified as hedges | – | – | – | (20,400) | (20,400) | 49,185 | 28,785 |
| **Accumulated Other Comprehensive Income (Loss)** | $(1,681) | $(33,142) | $(34,823) | $12,488 | $(22,335) | $(11,832) | $(34,167) |

(See Risk management in Note 1.)

## NOTE 15 Retirement Benefits

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **2002** | 2001 | **2002** | 2001 |
| (Thousands) | | | | |
| **Change in projected benefit obligation** | | | | |
| Benefit obligation at January 1 | **$1,369,448** | $1,242,769 | **$408,427** | $395,857 |
| Service cost | **29,318** | 23,967 | **6,040** | 5,091 |
| Interest cost | **111,943** | 90,949 | **32,215** | 25,024 |
| Plan participants' contributions | **-** | - | **212** | 255 |
| Plan amendments | **465** | 39,614 | **(11,922)** | (26,967) |
| Actuarial loss | **114,742** | 37,949 | **55,240** | 31,895 |
| Business combination | **501,454** | - | **92,198** | - |
| Curtailment | **-** | (670) | **-** | (394) |
| Special termination benefits | **64,909** | 2,551 | **-** | - |
| Benefits paid | **(98,415)** | (67,681) | **(25,140)** | (22,334) |
| Projected benefit obligation at December 31 | **$2,093,864** | $1,369,448 | **$557,270** | $408,427 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | **$1,822,052** | $1,925,905 | **$38,634** | $40,226 |
| Actual return on plan assets | **(244,955)** | (37,564) | **(3,248)** | (1,804) |
| Employer contributions | **329** | 433 | **23,215** | 22,291 |
| Plan participants' contributions | **-** | - | **212** | 255 |
| Business combination | **585,390** | - | **-** | - |
| Adjustment | **-** | 959 | **415** | - |
| Benefits paid | **(98,415)** | (67,681) | **(25,140)** | (22,334) |
| Fair value of plan assets at December 31 | **$2,064,401** | $1,822,052 | **$34,088** | $38,634 |
| Funded status | **$(29,463)** | $452,604 | **$(523,182)** | $(369,793) |
| Unrecognized net actuarial loss (gain) | **527,617** | (59,273) | **106,401** | 46,983 |
| Unrecognized prior service cost (benefit) | **50,741** | 58,277 | **(54,929)** | (60,365) |
| Unrecognized net transition (asset) obligation | **(8,469)** | (15,707) | **80,661** | 100,384 |
| Prepaid (accrued) benefit cost | **$540,426** | $435,901 | **$(391,049)** | $(282,791) |
| **Amounts recognized in the balance sheet** | | | | |
| Prepaid benefit cost | **$540,426** | $435,901 | **$99** | $516 |
| Accrued benefit cost | **-** | - | **(391,148)** | (283,307) |
| Additional minimum liability | **(185,321)** | (43,872) | **-** | - |
| Intangible asset | **6,226** | 2,517 | **-** | - |
| Regulatory liability | **76,913** | 37,022 | **-** | - |
| Accumulated other comprehensive income | **102,182** | 4,333 | **-** | - |
| Net amount recognized | **$540,426** | $435,901 | **$(391,049)** | $(282,791) |

CMP Group's, CNE's and CTG Resources' postretirement benefits were partially funded as of December 31, 2002 and 2001.

The company recorded a minimum pension liability of $185 million at December 31, 2002, as required by Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions. The effect of the minimum pension liability is 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 increase in the unfunded accumulated benefit obligation is primarily due to a reduction in the assumed discount rate, investment market conditions and a voluntary early retirement program offered by the company as part of its restructuring. (See Note 2.)

| | Pension Benefits | | | Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | **2002** | 2001 | 2000 | **2002** | 2001 | 2000 |
| **Weighted-average assumptions as of December 31** | | | | | | |
| Discount rate | **6.5%** | 7.0% | 7.25% | **6.5%** | 7.0% | 7.25% |
| Expected return on plan assets | **9.0%** | 9.0% | 9.0% | **9.0%** | 9.0% | 9.0% |
| Rate of compensation increase | **4.0%** | 4.0% | 4.0% | **4.0%** | 4.0% | 4.0% |

As of December 31, 2002, the company decreased its discount rate from 7.0% to 6.5% and its expected return on plan assets from 9.0% to 8.75% effective January 1, 2003.

The company assumed a 10% annual rate of increase in the costs of covered health care benefits for 2003 that gradually decreases to 5% by the year 2006.

| | Pension Benefits | | | Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | **2002** | 2001 | 2000 | **2002** | 2001 | 2000 |
| (Thousands) | | | | | | |
| **Components of net periodic benefit cost** | | | | | | |
| Service cost | **$29,318** | $23,967 | $20,979 | **$6,040** | $5,091 | $7,031 |
| Interest cost | **111,943** | 90,949 | 70,486 | **32,215** | 25,024 | 24,213 |
| Expected return on plan assets | **(190,541)** | (161,731) | (123,772) | **(2,993)** | (3,378) | (1,559) |
| Amortization of prior service cost | **8,035** | 7,822 | 1,706 | **(6,761)** | (6,753) | – |
| Recognized net actuarial gain | **(36,686)** | (41,750) | (40,103) | **1,647** | (4,122) | (2,630) |
| Amortization of transition (asset) obligation | **(7,238)** | (7,238) | (7,238) | **9,126** | 9,126 | 9,126 |
| Special termination benefits | **64,909** | 2,551 | – | **–** | – | – |
| Deferral for future recovery | **(32,086)** | – | – | **–** | – | (5,395) |
| Net periodic benefit cost | **$(52,346)** | $(85,430) | $(77,942) | **$39,274** | $24,988 | $30,786 |

Net periodic benefit cost is included in other operating expenses on the consolidated statements of income. 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 $88 million as of December 31, 2002, and $68 million as of December 31, 2001. 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.

A 1% increase or decrease in the health care cost inflation rate from assumed 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 | $33 million | $(28 million) |

## NOTE 16 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 |
|---|---|---|---|---|
| **2002** | | | | |
| Operating Revenues | **$2,568,247** | **$1,032,539** | **$408,132** | **$4,008,918** |
| Depreciation and Amortization | **$162,515** | **$71,329** | **$13,152** | **$246,996** |
| Operating Income | **$449,029** | **$149,656** | **$(6,509)** | **$592,176** |
| Interest Charges, Net | **$183,716** | **$73,177** | **$854** | **$257,747** |
| Income Taxes | **$94,238** | **$26,557** | **$(22,271)** | **$98,524** |
| Net Income | **$170,337** | **$51,128** | **$(32,862)** | **$188,603** |
| Total Assets | **$6,035,461** | **$3,058,885** | **$1,175,533** | **$10,269,879** |
| Capital Spending | **$137,414** | **$86,301** | **$5,672** | **$229,387** |
| 2001 | | | | |
| Operating Revenues | $2,504,896 | $1,026,124 | $228,767 | $3,759,787 |
| Depreciation and Amortization | $118,882 | $75,432 | $9,967 | $204,281 |
| Operating Income | $553,421 | $89,518 | $(6,051) | $636,888 |
| Interest Charges, Net | $154,011 | $55,785 | $7,232 | $217,028 |
| Income Taxes | $178,125 | $18,144 | $(41,890) | $154,379 |
| 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 |
| 2000 | | | | |
| Operating Revenues | $2,023,610 | $772,131 | $163,779 | $2,959,520 |
| Depreciation and Amortization | $105,067 | $49,769 | $10,688 | $165,524 |
| Operating Income | $482,657 | $72,729 | $(41,465) | $513,921 |
| Interest Charges, Net | $105,826 | $41,229 | $5,448 | $152,503 |
| Income Taxes | $146,529 | $12,182 | $(3,150) | $155,561 |
| Net Income | $228,971 | $15,632 | $(9,569) | $235,034 |
| Total Assets | $4,212,623 | $2,406,848 | $394,257 | $7,013,728 |
| Capital Spending | $70,651 | $68,170 | $29,499 | $168,320 |

## **NOTE 17 Quarterly Financial Information (Unaudited)**

| **Quarter Ended**<br>(Thousands, except per share amounts) | **March 31** | **June 30** | **September 30** | **December 31** |
|---|---|---|---|---|
| **2002** | | | | |
| Operating Revenues | **$1,028,578** | **$714,874** | **$1,016,189** | **$1,249,277** |
| Operating Income | **$238,869** | **$81,476** | **$113,500** | **$158,331** |
| Net Income | **$105,570**[1] | **$5,323**[1] | **$23,742** | **$53,968**[2] |
| Earnings Per Share, | | | | |
| basic and diluted[1] | **$.90**[1] | **$.05**[1] | **$.16** | **$.37**[2] |
| Dividends Per Share | **$.24** | **$.24** | **$.24** | **$.24** |
| Average Common Shares Outstanding | **116,720** | **117,820** | **144,621** | **144,849** |
| Common Stock Price[3] | | | | |
| High | **$21.92** | **$23.13** | **$22.53** | **$22.70** |
| Low | **$18.50** | **$20.92** | **$15.75** | **$18.25** |
| 2001 | | | | |
| Operating Revenues | $1,271,139 | $849,010 | $798,848 | $840,790 |
| Operating Income | $262,528 | $90,161 | $94,567 | $189,632 |
| Net Income (Loss) | $115,601 | $26,574 | $(21,057)[1] | $66,489 |
| Earnings (Loss) Per Share, | | | | |
| basic and diluted | $.98 | $.23 | $(.18)[1] | $.57 |
| Dividends Per Share | $.23 | $.23 | $.23 | $.23 |
| Average Common Shares Outstanding | $117,386 | 116,399 | 116,436 | 116,623 |
| Common Stock Price[3] | | | | |
| High | $20.31 | $21.20 | $22.14 | $21.49 |
| Low | $16.96 | $17.41 | $18.99 | $17.65 |

(1) Includes the effect of writedowns of CMP Group's investment in NEON Communications, Inc. that decreased net income and earnings per share as follows: $6 million and five cents in the first quarter of 2002, $1 million and one cent in the second quarter of 2002 and $46 million and 39 cents in the third quarter of 2001.

(2) 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.

(3) The company's common stock is listed on the New York Stock Exchange. The number of shareholders of record was 39,620 at December 31, 2002.

# Report of Management

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 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. In addition, the company's independent accountants, 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 accountants concerning internal controls and corrective measures are taken when considered appropriate. In addition, a Code of Conduct addresses areas of compliance and provides employees 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 outside directors, meets regularly with management, the internal auditor and the independent accountants 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 accountants have direct access to the audit committee, independent of management.

The company assessed its internal control system as of December 31, 2002, in relation to criteria for effective internal control over financial reporting and the safeguarding of assets described in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, the company believes that, as of December 31, 2002, its system of internal control over financial reporting and over the safeguarding of assets against loss or unauthorized use met those criteria.

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

# Report of Independent Accountants

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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 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 our opinion.

As discussed in Notes 1 and 14 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). In addition, as discussed in Notes 1 and 4 to the consolidated financial statements, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets.

PricewaterhouseCoopers LLP

New York, New York
January 31, 2003

# Selected Financial Data

| | 2002[1] | 2001 | 2000[4] | 1999 | 1998 | 1997 |
|---|---|---|---|---|---|---|
| (Thousands, except per share amounts) | | | | | | |
| **Operating Revenues** | | | | | | |
| Sales and services | **$4,008,918** | $3,759,787 | $2,959,520 | $2,278,608 | $2,499,568 | $2,170,102 |
| **Operating Expenses** | | | | | | |
| Electricity purchased and fuel used in generation | **1,276,087** | 1,334,507 | 1,073,728 | 905,367 | 992,236 | 643,063 |
| Natural gas purchased | **603,258** | 694,038 | 496,509 | 186,722 | 158,757 | 164,661 |
| Gasoline, propane and oil purchased | **143,770** | 3,688 | 1,560 | – | – | – |
| Other operating expenses | **713,384** | 566,498 | 434,405 | 312,129 | 367,897 | 406,830 |
| Maintenance | **162,122** | 139,395 | 108,106 | 85,849 | 111,503 | 110,373 |
| Depreciation and amortization | **246,996** | 204,281 | 165,524 | 648,970[5] | 191,462 | 202,151 |
| Other taxes | **230,558** | 192,772 | 165,767 | 179,028 | 204,483 | 205,974 |
| 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** | **3,416,742** | 3,122,899 | 2,445,599 | 1,716,025 | 2,026,338 | 1,733,052 |
| **Operating Income** | **592,176** | 636,888 | 513,921 | 562,583 | 473,230 | 437,050 |
| **Writedown of Investment** | **12,209** | 78,422[3] | – | – | – | – |
| **Other (Income) and Deductions** | **2,964** | (15,041) | (30,157) | (12,573) | 7,474 | 11,113 |
| **Interest Charges, Net** | **257,747** | 217,066 | 152,520 | 132,908 | 125,557 | 123,199 |
| **Preferred Stock Dividends of Subsidiaries** | **32,129** | 14,455 | 963 | 2,706 | 8,583 | 9,342 |
| **Income Before Income Taxes** | **287,127** | 341,986 | 390,595 | 439,542 | 331,616 | 293,396 |
| **Income Taxes** | **98,524** | 154,379 | 155,561 | 220,791 | 137,411 | 118,185 |
| **Net Income** | **188,603**[2] | 187,607[3] | 235,034 | 218,751 | 194,205 | 175,211[6] |
| **Common Stock Dividends** | **125,456** | 107,342 | 99,606 | 98,725 | 100,487 | 95,496 |
| **Retained Earnings Increase** | **$63,147** | $80,265 | $135,428 | $120,026 | $93,718 | $79,715 |
| **Average Common Shares Outstanding** | **131,117** | 116,708 | 114,213 | 116,316 | 128,742 | 136,306 |
| **Earnings Per Share, basic and diluted** | **$1.44**[2] | $1.61[3] | $2.06 | $1.88 | $1.51 | $1.29[6] |
| **Dividends Paid Per Share** | **$.96** | $.92 | $.88 | $.84 | $.78 | $.70 |
| **Book Value Per Share of Common Stock at Year End** | **$16.97** | $15.26 | $14.59 | $12.84 | $13.61 | $13.36 |
| **Capital Spending** | **$229,387** | $222,875 | $168,320 | $82,674 | $137,350 | $129,551 |
| **Total Assets** | **$10,269,879** | $7,269,232 | $7,013,728 | $3,773,171 | $4,902,085 | $5,044,914 |
| **Long-term Obligations, Capital Leases and Redeemable Preferred Stock** | **$3,721,959** | $2,816,278 | $2,346,814 | $1,235,089 | $1,460,120 | $1,475,224 |

All per share amounts and shares outstanding have been restated to reflect the two-for-one common stock split effective April 1, 1999.

Reclassifications: Certain amounts included in Selected Financial Data have been reclassified to conform with the 2002 presentation.

(1) 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.

(2) Includes the writedown of CMP Group's investment in NEON Communications, Inc. that decreased net income $7 million and earnings per share six cents and the effect of restructuring expenses that decreased net income $24 million and earnings per share 19 cents.

(3) Includes the writedown of CMP Group's investment in NEON Communications, Inc. that decreased net income $46 million and earnings per share 39 cents.

(4) 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's results beginning with September 2000.

(5) Depreciation and amortization includes accelerated amortization of NMP2 related to the sale of the company's coal-fired generation assets, authorized by the NYPSC.

(6) Includes the effect of fees related to an unsolicited tender offer that decreased net income $17 million and earnings per share 12 cents.

# Energy Distribution Statistics

| | 2002 | 2001 | 2000 | 1999 | 1998 | 1997 |
|---|---|---|---|---|---|---|
| (Thousands) | | | | | | |
| **Electric Deliveries** | | | | | | |
| (Megawatt-hours) | | | | | | |
| Residential | **10,226** | 8,594 | 6,473 | 5,447 | 5,199 | 5,267 |
| Commercial | **8,019** | 6,527 | 4,504 | 3,517 | 3,428 | 3,495 |
| Industrial | **6,694** | 6,525 | 4,613 | 3,383 | 3,222 | 3,065 |
| Other | **1,930** | 1,592 | 1,543 | 1,496 | 1,428 | 1,411 |
| **Total Retail** | **26,869** | 23,238 | 17,133 | 13,843 | 13,277 | 13,238 |
| Wholesale | **5,330** | 6,048 | 6,214 | 10,978 | 22,711 | 10,406 |
| **Total Electric Deliveries** | **32,199** | 29,286 | 23,347 | 24,821 | 35,988 | 23,644 |
| **Electric Revenues** | | | | | | |
| Residential | **$1,073,586** | $998,846 | $820,093 | $747,964 | $720,546 | $728,777 |
| Commercial | **609,165** | 622,996 | 460,453 | 393,623 | 393,857 | 403,481 |
| Industrial | **313,622** | 314,527 | 263,633 | 237,637 | 246,589 | 243,868 |
| Other | **175,130** | 162,987 | 153,283 | 159,730 | 158,215 | 157,517 |
| **Total Retail** | **2,171,503** | 2,099,356 | 1,697,462 | 1,538,954 | 1,519,207 | 1,533,643 |
| Wholesale | **190,090** | 238,094 | 212,630 | 312,727 | 611,852 | 232,138 |
| Other | **206,654** | 167,446 | 113,518 | 37,637 | 28,810 | 26,383 |
| **Total Electric Revenues** | **$2,568,247** | $2,504,896 | $2,023,610 | $1,889,318 | $2,159,869 | $1,792,164 |
| **Natural Gas Deliveries** | | | | | | |
| (Dekatherms) | | | | | | |
| Residential | **62,748** | 52,846 | 42,238 | 23,327 | 20,960 | 24,357 |
| Commercial | **21,190** | 20,699 | 15,823 | 8,247 | 7,909 | 10,178 |
| Industrial | **2,934** | 2,847 | 2,690 | 1,669 | 1,779 | 2,409 |
| Other | **14,507** | 12,726 | 10,074 | 2,677 | 2,568 | 2,735 |
| Transportation of customer-owned natural gas | **80,480** | 58,882 | 37,314 | 23,426 | 20,962 | 19,645 |
| **Total Retail** | **181,859** | 148,000 | 108,139 | 59,346 | 54,178 | 59,324 |
| Wholesale | **7,074** | 9,298 | 10,674 | 8,617 | 7,527 | 3,027 |
| **Total Natural Gas Deliveries** | **188,933** | 157,298 | 118,813 | 67,963 | 61,705 | 62,351 |
| **Natural Gas Revenues** | | | | | | |
| Residential | **$594,279** | $576,115 | $390,794 | $181,579 | $171,437 | $190,564 |
| Commercial | **192,023** | 226,215 | 145,318 | 63,112 | 61,059 | 83,091 |
| Industrial | **20,883** | 26,220 | 19,339 | 8,123 | 8,155 | 13,044 |
| Other | **83,735** | 89,524 | 68,652 | 14,745 | 14,257 | 17,839 |
| Transportation of customer-owned natural gas | **84,927** | 73,213 | 59,901 | 33,572 | 29,589 | 21,949 |
| **Total Retail** | **975,847** | 991,287 | 684,004 | 301,131 | 284,497 | 326,487 |
| Wholesale | **17,260** | 37,748 | 55,184 | 21,831 | 17,791 | 9,114 |
| Other | **39,432** | (2,911) | 32,943 | 8,783 | 3,743 | 2,224 |
| **Total Natural Gas Revenues** | **$1,032,539** | $1,026,124 | $772,131 | $331,745 | $306,031 | $337,825 |

# 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 and City University Television, all in New York, New York.

**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 the Catholic Health System of Western New York and of HealthNow New York, Inc., DBA Blue Cross & Blue Shield of Western New York, both 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 June 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

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

*Compensation and Management Succession:* Castiglia, Aurelio, Lynch

*Nominating and Corporate Governance:* Aurelio, DeFleur, Keeler, 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 – The Energy Network, Inc.*

**Kenneth M. Jasinski**
*Executive Vice President and Chief Financial Officer*

**Robert D. Kump**
*Vice President, Treasurer & Secretary*

**James P. Laurito**
*President – Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company*

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

**Patrick Neville**
*Vice President – Information Technology*

**Clifton B. Olson**
*Vice President – Energy Supply*

**Jessica Raines**
*Vice President – Supply Chain*

**Robert E. Rude**
*Vice President and Controller*

**Angela M. Sparks-Beddoe**
*Vice President – Public Affairs*

**Ralph R. Tedesco**
*President – New York State Electric & Gas Corporation*

**Denis E. Wickham**
*Senior Vice President – Transmission and Energy Supply*

**Paul C. Wilkens**
*President – Rochester Gas and Electric Corporation*

# Shareholder Information

### Shareholder Services

Shareholder Services representatives are available between 8 a.m. and 4:30 p.m. (Eastern Time) on regular business days at 1-800-225-5643. Or you may write to:

*Energy East Corporation*
*Attention: Shareholder Services*
*P.O. Box 3200*
*Ithaca, NY 14852-3200*

Please contact Shareholder Services with questions regarding:

- our dividend reinvestment and stock purchase plan
- dividend payments or lost dividend checks
- direct deposit of dividends
- replacement of lost certificates
- a change of address
- annual report requests
- our annual meeting of shareholders

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

### The Shareholder Connection: 1-800-225-5643

Investor information is available at your fingertips. This service provides quick access to Energy East's common stock closing price as well as timely dividend and news release information 24 hours a day, seven days a week.

### Internet Address: www.energyeast.com

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

### Transfer Agent and Registrar: Mellon Investor Services

To present certificates for transfer (certified or registered mail is recommended) write to:

*Mellon Investor Services*
*P.O. Box 3312*
*South Hackensack, NJ 07606-1912*

To request transfer instructions, write to:

*Mellon Investor Services*
*P.O. Box 3315*
*South Hackensack, NJ 07606-1915*

### Investor Relations

Members of the financial community may contact our Manager, Investor Relations by phone at 607-347-2561 or by fax at 607-347-2560.

### Principal Offices

*P.O. Box 12904, Albany, New York 12212-2904*

*217 Commercial Street, Portland, Maine 04101*

### Trading Symbol: EAS

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

### Annual Meeting

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

# Subsidiary Companies

**Central Maine Power Company (CMP)**

83 Edison Drive, Augusta, ME 04336

**www.cmpco.com**

**Connecticut Natural Gas Corporation (CNG)**

10 State House Square, 6th Floor, P.O. Box 1500, Hartford, CT 06144-1500

**www.cngcorp.com**

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

Carrigg Center – Corporate Drive, P.O. Box 5224, Binghamton, NY 13902-5224

Ithaca-Dryden Road, P.O. Box 3287, Ithaca, NY 14852-3287

**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**

**Energetix, Inc.**

755 Brooks Avenue, Rochester, NY 14619

**Energy East Enterprises, Inc.**

81 State Street, Stephens Square, 5th Floor, Binghamton, NY 13901

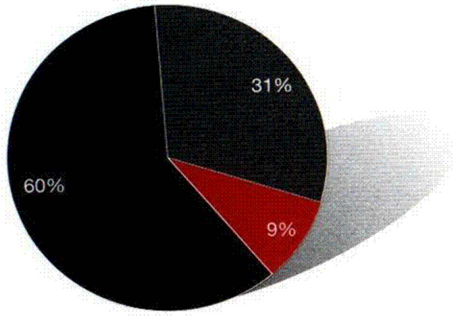
**The Energy Network, Inc.**

81 State Street, Stephens Square, 5th Floor, Binghamton, NY 13901

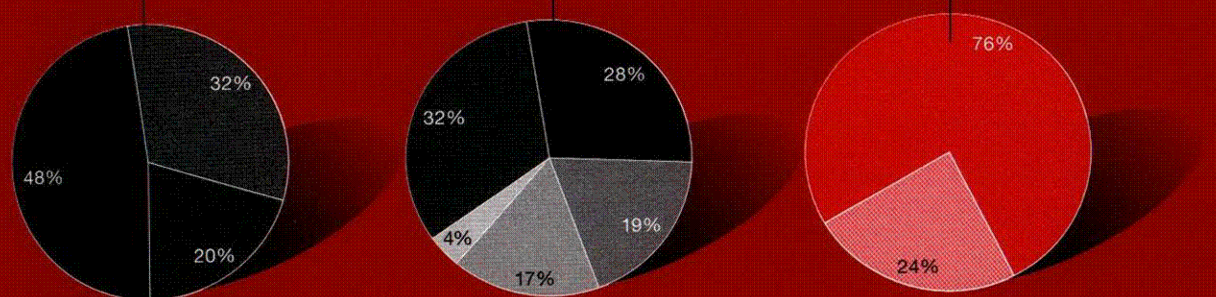
**We grew in 2002** with the RGS Energy strategic combination. Energy East is one of the most diversified energy delivery providers in the Northeast, with nearly 3 million customers. Energy East's customer base has almost tripled in three years, providing us with new opportunities for growth and profitability.

# at-a-glance

c02




**Energy East:** 2,921,000 customers
Electricity · Natural Gas · Other




**Electricity:** 1,757,000 customers

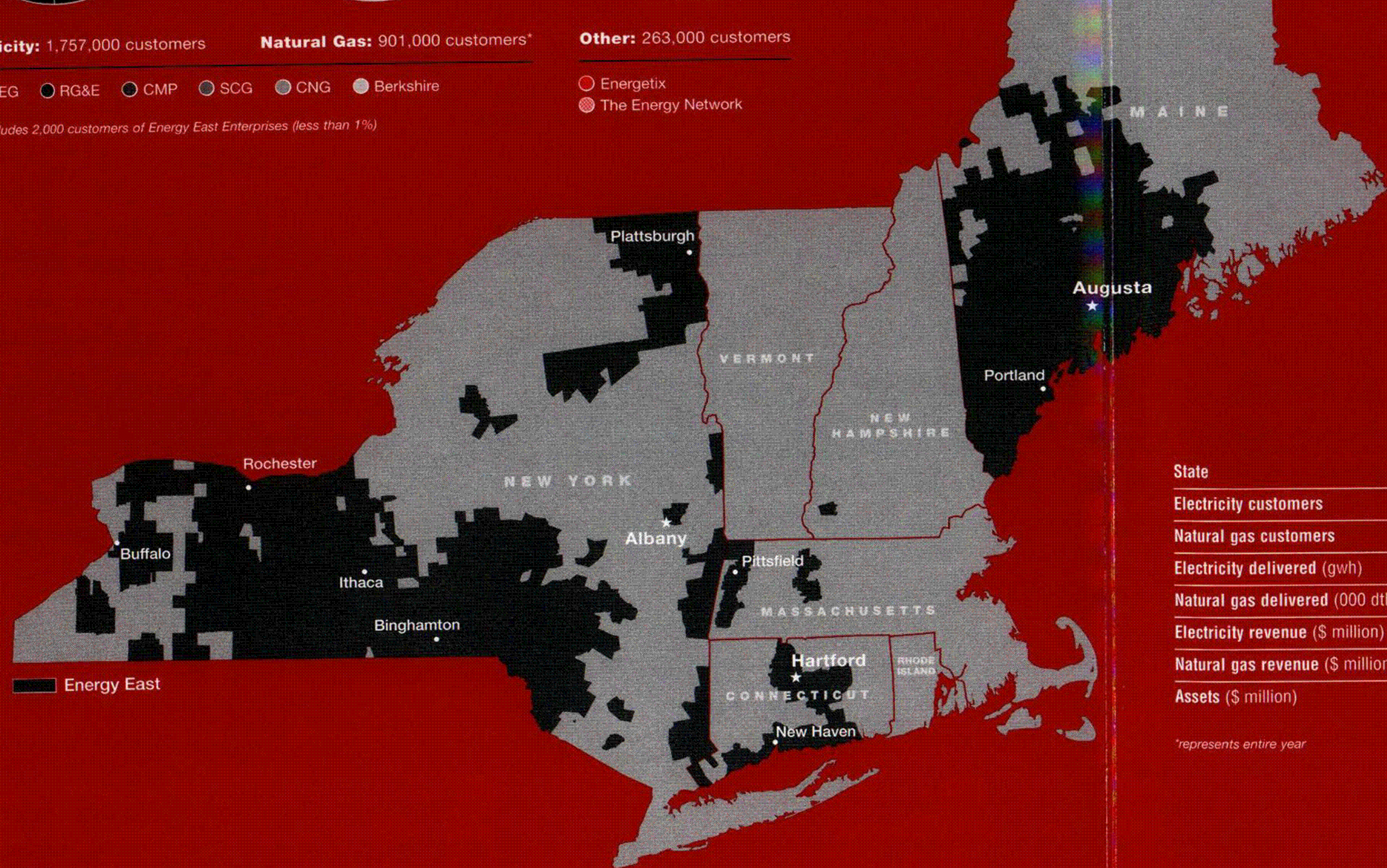
**Natural Gas:** 901,000 customers*

NYSEG · RG&E · CMP · SCG · CNG · Berkshire

*total includes 2,000 customers of Energy East Enterprises (less than 1%)

**Other:** 263,000 customers

Energetix · The Energy Network




### Other Businesses

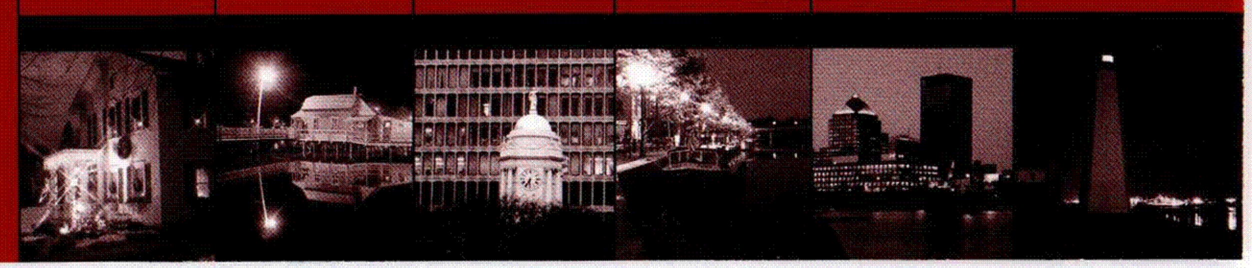
**Energetix**
Energetix is the nonutility subsidiary of RGS Energy. Current operations include the distribution of liquid fuels and the marketing of electricity and natural gas.

**The Energy Network**
Our nonutility focus currently includes peaking generation, retail energy marketing and telecommunications areas, which complement our core utility business.

**Energy East Enterprises**
Current regulated operations include a gas distribution business in Maine and New Hampshire and the expansion of a high-deliverability gas storage facility in upstate New York. Both areas provide attractive growth opportunities.

| | Berkshire | CMP | CNG | NYSEG | RG&E | SCG |
|---|---|---|---|---|---|---|
| State | Massachusetts | Maine | Connecticut | New York | New York | Connecticut |
| **Electricity customers** | | 564,000 | | 838,000 | 355,000 | |
| **Natural gas customers** | 35,000 | | 152,000 | 250,000 | 291,000 | 171,000 |
| **Electricity delivered** (gwh) | | 11,263 | | 16,211 | 9,159* | |
| **Natural gas delivered** (000 dth) | 7,709 | | 34,520 | 64,485 | 52,012* | 32,510 |
| **Electricity revenue** ($ million) | | 654 | | 1,545 | 706* | |
| **Natural gas revenue** ($ million) | 48 | | 267 | 333 | 287* | 253 |
| **Assets** ($ million) | 204 | 1,763 | 686 | 3,033 | 2,491 | 859 |

*represents entire year



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

# vision

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.

EnergyEast