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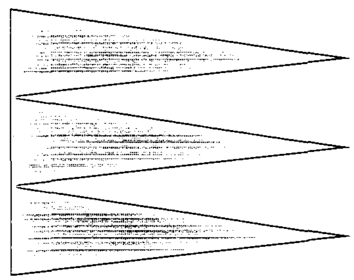
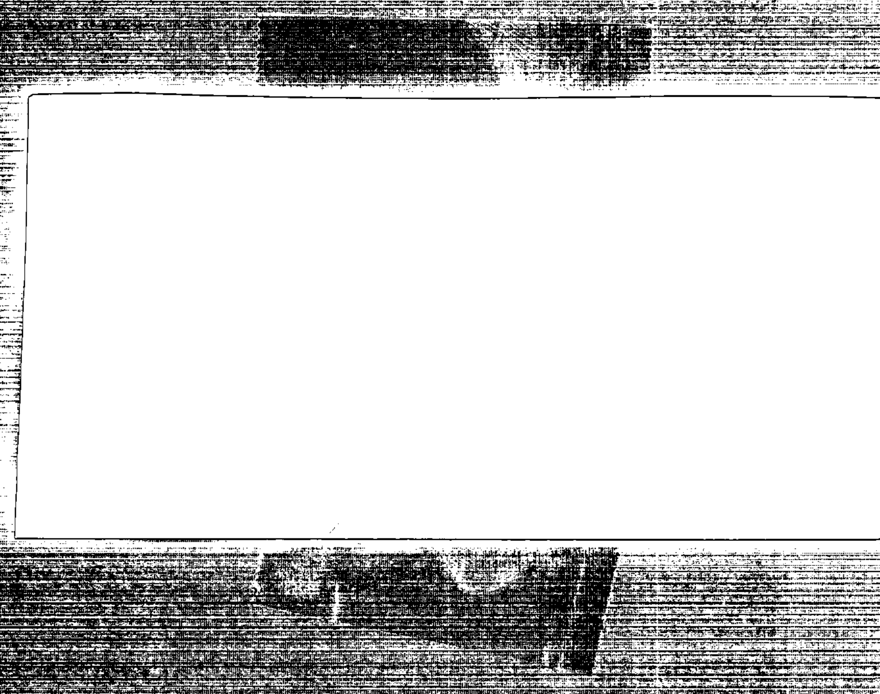
Energy East Corporation Annual Report 2001



A year of growth and repositioning...

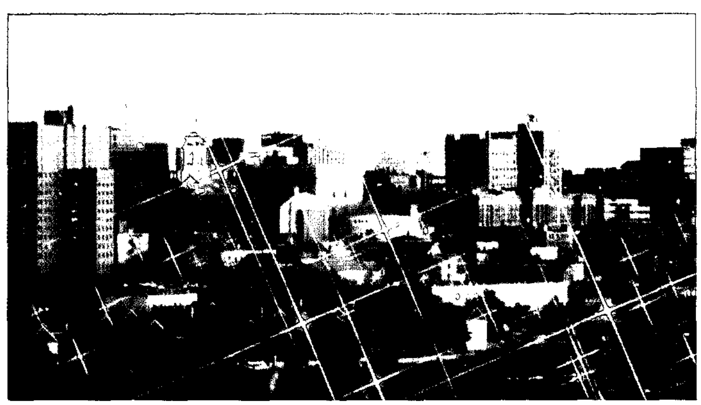
By year end 2002, Energy East's customer base will have nearly tripled in three years, providing new opportunities for growth and profitability.



Dear Shareholders:

Notwithstanding the challenges that tested our country, our industry and our company this past year, Energy East emerged from 2001 better equipped to create additional value for shareholders. For Energy East, 2001 was a year of growth and repositioning. It was a year that solidified our role as a leading super regional energy services and delivery company in the Northeast, with nationally recognized customer satisfaction and service reliability.

In last year's Annual Report I discussed our growth strategy, including the four mergers we completed in 2000, as well as our focus on capturing merger savings and rationalizing our nonutility businesses.



Portland, Maine at twilight

With the first full year of operations behind us, we can report that we made excellent progress on each of these initiatives. Earnings from the merged companies met our expectations in 2001, and the earnings contributions of our nonutility businesses were significantly better as we exited several and improved the profitability of others.

2001 Highlights

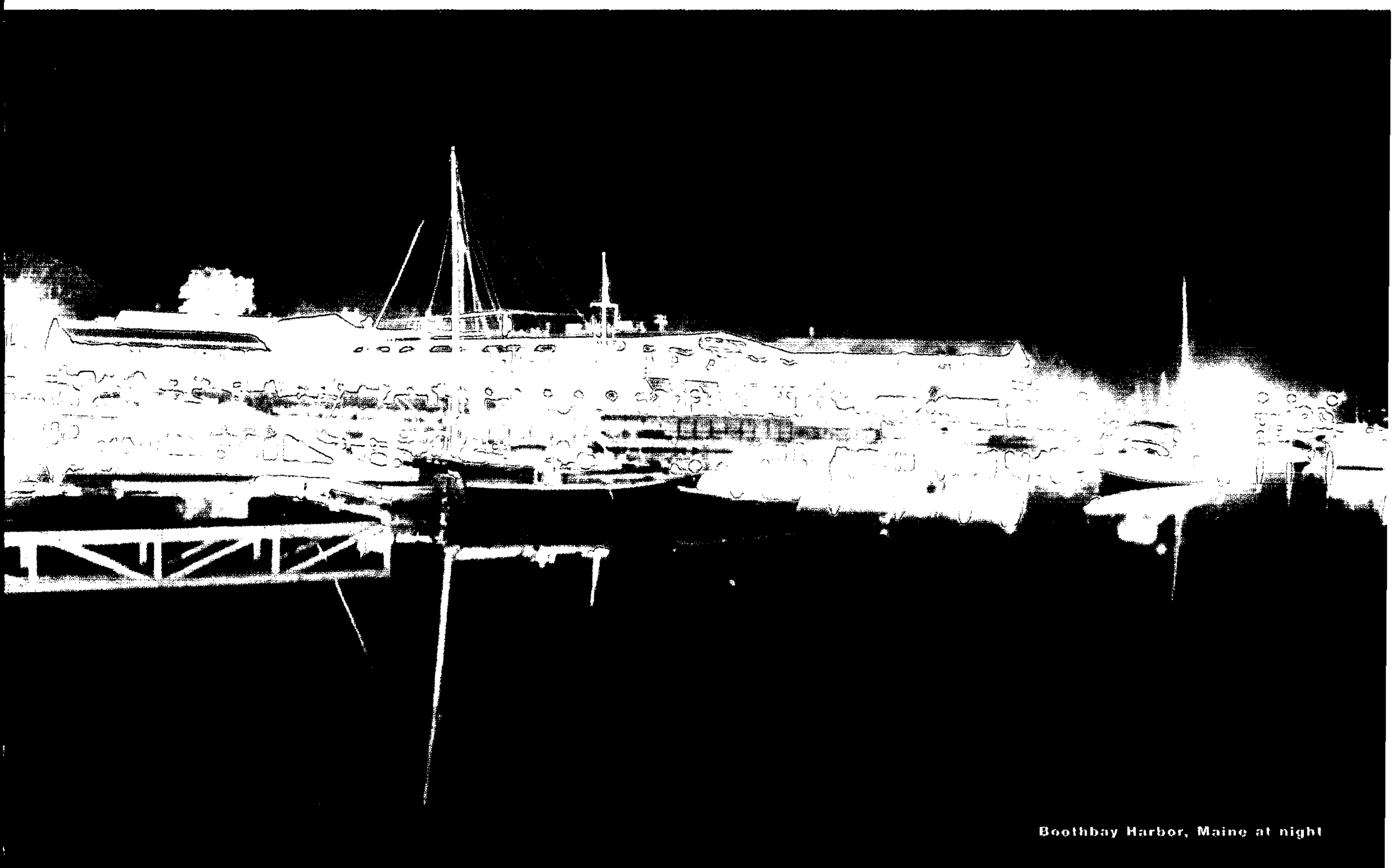
Dividend raised 5% to 92¢ per year

Strategic combination announced with RGS Energy Group

January

February

Earnings were down in 2001, predominantly because of a non-cash writedown of an investment in NEON Communications, Inc., a telecommunications company which saw a permanent drop in its stock price during 2001. Effective cost control at our operating companies helped offset lower sales due to the very mild weather experienced through much of 2001, as well as extremely high natural gas prices early in the year.



Boothbay Harbor, Maine at night

NYSEG files plan to freeze customer electric delivery and supply prices

System wide gas supply and optimization plan announced

2.5% interest in Millstone #3 nuclear plant sold

23¢ common stock dividend declared

March

April

Over the past two years, we have worked hard on developing long term performance based rate plans in Connecticut, Maine, Massachusetts and New York which provide competitive prices and choice for customers and earnings growth opportunities for shareholders. The New York State Public Service Commission recently approved a five year, performance based electric rate plan for NYSEG, our largest subsidiary. It provides an immediate rate reduction for customers, and the option for customers to choose a fixed rate from NYSEG that includes both the cost of supply and delivery. The competitive energy markets are still developing, and we believe it is critical that we be allowed to provide our customers the option to avoid volatile energy supply prices.

New gas-fired plant begins operation in Pennsylvania

Shareholders overwhelmingly approve RGS merger

Construction begins on extension of our natural gas distribution system in Maine

May June

Line mechanic repairing power line

This settlement also approves our proposed merger with RGS Energy, and specifies that synergies generated by the merger be shared equally between shareholders and customers. Lower earnings will result at NYSEG, and Energy East, in 2002, as NYSEG's electric rates now reflect the disposal of generating plants which was mandated by New York State regulators in 1998.

Downtown Hartford, Connecticut

In a way, 2002 will mark the end of our repositioning. With the approval of the NYSEG electric plan, we now intend to introduce long term incentive proposals at NYSEG's natural gas business and at Rochester Gas and Electric. We would then have performance based rate plans in place at each of our operating utilities which would allow shareholders to benefit from the growth and synergies we create.

We expect the merger with RGS Energy to occur in the second quarter of 2002. By combining complementary geographies, strengths and skills, we believe we will emerge as the energy leader in upstate New York.

23¢ common stock dividend declared

In a national survey, NYSEG and CMP earned the third highest customer satisfaction score in the Eastern Region

Plans announced for development of an expanded natural gas storage facility in upstate New York

Agreement reached to sell 4% interest in Vermont Yankee nuclear plant

July — August

Holiday lights display – Stockbridge, Massachusetts

With RGS, Energy East will serve nearly 3 million customers, including almost 2 million electric, 1 million natural gas and 250,000 nonutility customers. Additionally, we will have a wider range of options for meeting our customers' supply requirements. We are enthusiastic about the opportunities this merger would create.

Given all the press regarding the collapse of Enron, it is appropriate to share with you my thoughts on this fiasco. First, and foremost, our dealings with Enron were minimal, and their bankruptcy will not have a financial impact on us. However, as we reflect on the Enron situation, it is important to reiterate a point made in last year's Annual Report. This is a changed and changing business.

Orchestra musicians on stage – Tanglewood, Massachusetts

Finger Lakes cruise boat – Seneca Falls, New York

From serious power shortages, to commodity price surges, to the complete failure of one of the largest companies in the world, we have clearly seen more than enough challenges emanating from regulators' efforts to create competition in the supply of electricity. All of us at Energy East are acutely aware of the need to manage these new risks and protect our customers and shareholders. At the same time, we are always looking for new ways to create value for shareholders.

Energy East contributes funds, personnel and equipment to World Trade Center relief efforts

23¢ common stock dividend declared

Natural gas service extended to Portland, Connecticut

September

October

I believe that the people who work at Energy East are among the best in the business. It is their integrity and professionalism that make Energy East an industry leader today. On behalf of the Board of Directors, I thank them and you, our shareholders, for your support and confidence.

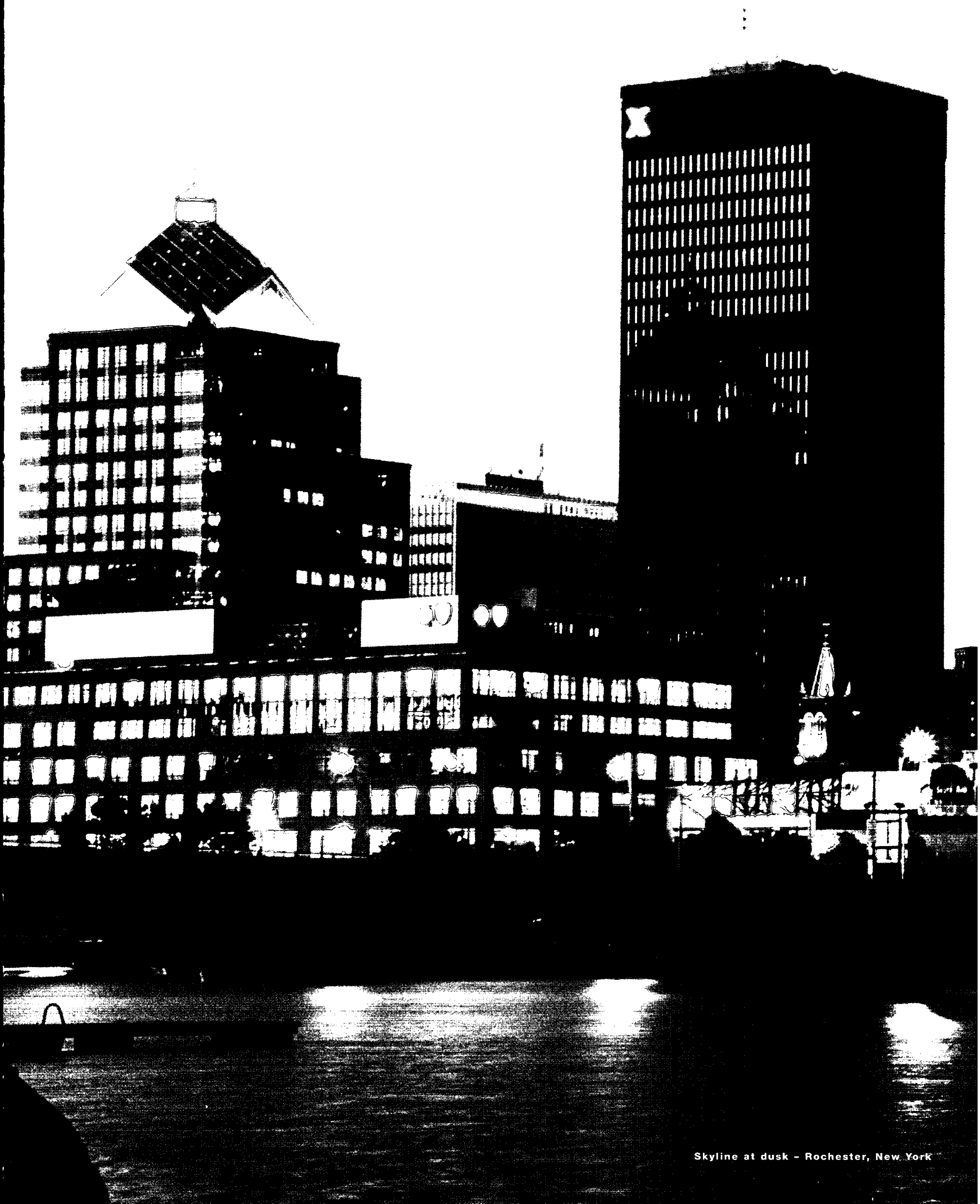
Wes Von Schack

Wesley W. von Schack
Chairman, President and Chief Executive Officer
February 28, 2002

18% interest in NMP2 nuclear plant sold

Natural gas service made available in the towns of Topsham and Brunswick, Maine

November December


Skyline at dusk – Rochester, New York

Merger History

1999

- Connecticut Energy merger announced
- CMP Group merger announced
- CTG Resources merger announced
- Berkshire Energy merger announced

2000

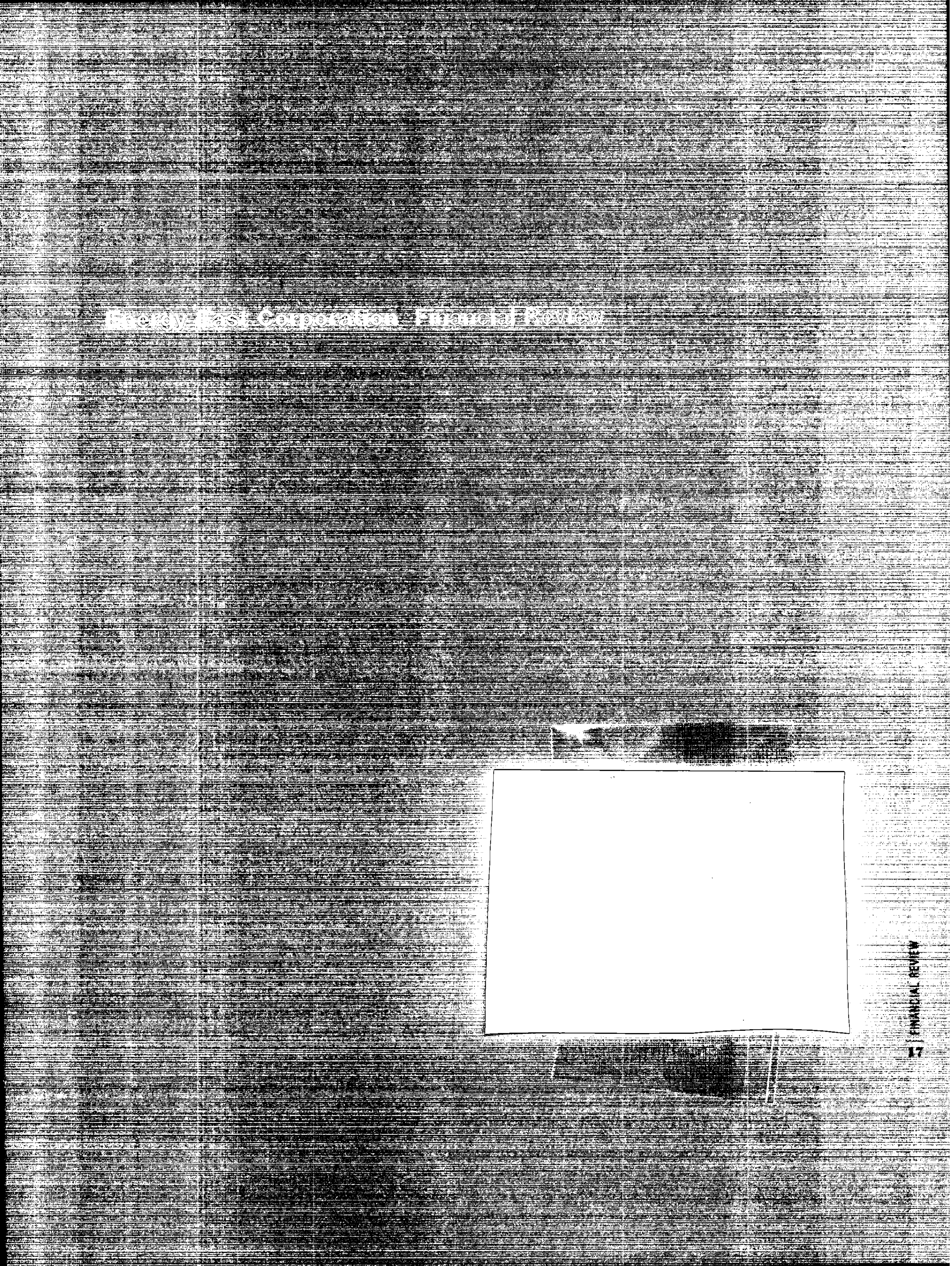
- Connecticut Energy merger closes
- Berkshire Energy, CTG Resources, CMP Group mergers close

2001

- RGS Energy Group merger announced

Harbor Lighthouse – coastal Connecticut

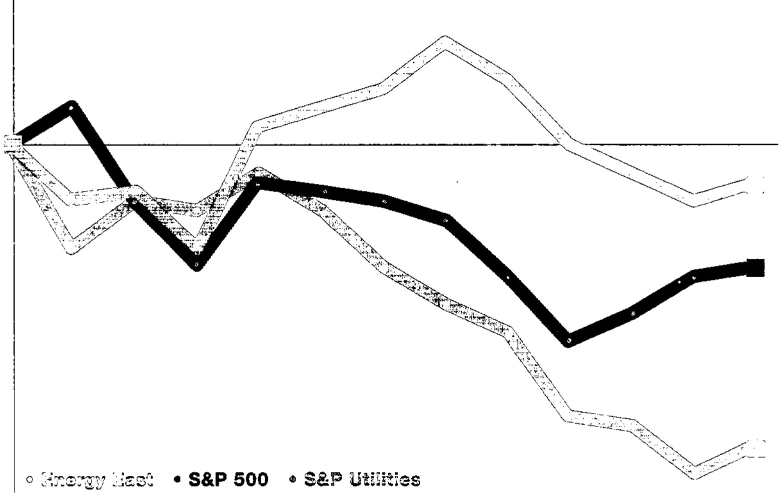
Energy East Corporation Financial Review



Per Common Share	2001	2000	% Change
Earnings	**$1.61**	$2.06	(22)
Dividends Paid	**$.92**	$.88	5
Book Value at Year End	**$15.26**	$14.59	5
Price at Year End	**$18.99**	$19.69	(4)
Other Common Stock Information (Thousands)			
Average Common Shares Outstanding	**116,708**	114,213	2
Common Shares Outstanding at Year End	**116,718**	117,656	(1)
Operating Results (Thousands)			
Total Operating Revenues	**$3,759,787**	$2,959,520	27
Total Operating Expenses	**$3,122,899**	$2,445,599	28
Net Income	**$187,607**	$235,034	(20)
Energy Distribution:			
Megawatt-hours –			
Retail Deliveries	**23,238**	17,133	36
Wholesale Deliveries	**6,048**	6,214	(3)
Dekatherms –			
Retail Deliveries	**148,000**	108,139	37
Wholesale Deliveries	**9,298**	10,674	(13)
Total Assets at Year End (Thousands)	**$7,269,232**	$7,013,728	4

Stock Performance

Calendar Year 2001



Liquidity and Capital Resources

Energy East Corporation and RGS Energy Merger Agreement

In February 2001 Energy East Corporation (the company) announced that it had entered into a merger agreement with RGS Energy Group, Inc. under which all of the outstanding common stock of RGS Energy would be exchanged for a combination of cash and Energy East common stock valued at approximately $1.4 billion in the aggregate. The company will also assume approximately $1 billion of RGS Energy debt. RGS Energy will become a wholly-owned subsidiary of the company and the transaction will be accounted for under the purchase method of accounting.

Under the merger agreement 45% of the RGS Energy common stock will be exchanged for Energy East common stock with a value of $39.50 per RGS Energy share, subject to restrictions on the minimum and maximum number of shares to be issued, and 55% of the RGS Energy common stock will be converted into $39.50 in cash per RGS Energy share. RGS Energy shareholders will be able to elect the form of consideration they wish to receive, subject to proration. The company intends to finance the cash portion of the transaction primarily through the issuance of long-term debt and trust preferred securities. (See Financing Activities.)

RGS Energy and Energy East each held their annual meeting on June 15, 2001: RGS Energy's shareholders approved the merger and Energy East's shareholders approved the issuance of Energy East shares in connection with the merger.

The merger is subject to, among other things, various regulatory approvals, including the New York State Public Service Commission (NYPSC), Federal Energy Regulatory Commission (FERC), Nuclear Regulatory Commission (NRC) and Securities and Exchange Commission (SEC). The company has made all required regulatory filings and received approval from FERC in September 2001 and NRC in December 2001 for the change in control of RGS Energy's nuclear generation assets. In addition, the transaction cleared anti-trust review by the U.S. Department of Justice in October 2001.

On January 15, 2002, the company and New York State Electric & Gas Corporation (NYSEG) reached settlement with the NYPSC Staff and several other parties on a joint proposal for the merger and a new five-year electric rate plan for NYSEG. (See NYSEG Electric Rate Settlement.) The NYPSC approved the joint proposal and merger on February 27, 2002. As a result of the passage of time in connection with reaching the settlement with the NYPSC, the company expects to complete its merger with RGS Energy in the second quarter of 2002.

Electric Delivery Business

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

SALE OF NINE MILE POINT 2 | On November 7, 2001, after receiving all regulatory approvals, NYSEG sold its 18% interest in the Nine Mile Point 2 nuclear generating station (NMP2) to Constellation Nuclear. For its share of NMP2, NYSEG received at closing $59 million in cash and a $59 million 11% promissory note, which will be paid in five annual payments unless it is prepaid.

On September 28, 2001, NYSEG and the Staff of the NYPSC reached agreement on a joint settlement with respect to the regulatory and ratemaking aspects of the sale of NYSEG's interest in NMP2. On October 26, 2001, the NYPSC issued an order approving the sale, which provided for an asset sale gain account of approximately $110 million to be established at the time of closing. Disposition of the asset sale gain is addressed in the new NYSEG electric rate settlement approved by the NYPSC on February 27, 2002. (See NYSEG Electric Rate Settlement.)

NYSEG's pre-existing decommissioning funds 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, at fixed prices, for 10 years. After the power purchase agreement is completed a revenue sharing agreement will begin. The revenue sharing agreement could provide NYSEG additional revenue through 2021, which would mitigate increases in electricity prices. Both agreements are based on plant output.

In 1999 the majority of NYSEG's investment in NMP2 was recovered through a gain on the sale of the company's coal-fired generation assets. The remaining balance was written off pursuant to Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.

SALE OF CMP NUCLEAR INTERESTS | On March 31, 2001, Central Maine Power Company (CMP) sold its 2.5% ownership interest in the Millstone Unit No. 3 nuclear unit. The net proceeds from the sale, $1.4 million including unfunded deferred taxes, were used to reduce a regulatory asset related to CMP's nonnuclear generating assets that were sold in April 1999. CMP contributed $1.3 million to the qualified nuclear trust fund, as part of the sale agreement, and is released from any liability for decommissioning the plant in the future.

On August 15, 2001, Vermont Yankee Nuclear Power Corporation reached an agreement to sell the Vermont Yankee nuclear power plant to Entergy Corporation. CMP has a 4% ownership interest in Vermont Yankee. The transaction includes 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. The sale is subject to the approval of the Public Service Board of Vermont, the NRC, the FERC and other regulatory authorities. On January 30, 2002, FERC issued an order approving the sale. (See Note 9 to the Consolidated Financial Statements.)

INDEPENDENT SYSTEM OPERATOR (ISO) | The New York Independent System Operator (NYISO) has operational control over certain transmission facilities of each of the New York transmission-owning utilities, including NYSEG. The NYISO administers centralized capacity, energy, transmission and ancillary service markets, including operating reserves markets in New York.

In January and February 2000 the NYISO's operating reserves markets experienced problems that resulted in substantial charges to all customers required to buy operating reserves, including NYSEG. Several parties, including NYSEG, commenced FERC and court proceedings in response to these problems. In May 2000 the FERC approved a bid cap effective March 28, 2000, for a portion of the operating reserves markets until the market problems are corrected and the NYISO demonstrates that all reserves markets are competitive, but did not order refunds of earlier higher operating reserves prices as sought by NYSEG. Several parties sought rehearing of FERC's order. On October 1, 2001, the United States District Court for the Northern District of New York issued a stay of NYSEG's action for a period of 12 months or until the FERC issues a decision on the parties' request for rehearing. On November 8, 2001, FERC issued an order denying rehearing and requiring the NYISO to resettle March 2000 operating reserves charges at higher prices. The NYISO sought rehearing of this order and rebilled customers, including NYSEG. NYSEG paid and expensed this additional reserve charge of $3 million.

REGIONAL TRANSMISSION ORGANIZATION | On July 12, 2001, FERC issued an order requiring the NYISO and neighboring New England and Mid-Atlantic independent system operators to negotiate to form a single Northeast Regional Transmission Organization (RTO). RTOs are similar to ISOs, but have more authority and cover broader geographic regions. The NYISO and other parties involved in negotiating the formation of the RTO participated in mediation facilitated by a FERC administrative law judge (ALJ) for 45 days, leading to a business plan detailing the process to develop a Northeast RTO. The business plan, coupled with an ALJ's report, have been submitted to the FERC. A FERC decision on the Northeast RTO is expected in the spring of 2002.

In October 2001 FERC also commenced a proceeding to consider national standard market design issues and is expected to engage in a rulemaking proceeding soon. NYSEG and CMP have consistently advocated the formation of a Northeast/Mid-Atlantic RTO, including PJM Interconnection, L.L.C., or functionally combined markets throughout the Northeast because they believe that a larger wholesale power market is essential to facilitate greater liquidity and competition. A Northeast RTO may include an independent transmission company which would be owned by participating transmission owners. The transmission company would share RTO responsibilities with an independent market administrator and would focus on transmission investment opportunities, instead of energy, capacity and other generation-based markets. The company is unable to predict the ultimate effect, if any, of the expected rulemaking on wholesale power markets and the company's transmission 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 and NYSEG 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. In October 2001 FERC also announced that it plans to engage in rulemaking proceedings on generation interconnection terms, conditions and cost allocation. The company is unable to predict the ultimate effect, if any, of the expected rulemaking on its transmission system.

ELECTRIC TRANSMISSION RATES | Rates charged for the use of the company's transmission system are subject to FERC approval. NYSEG filed a transmission rate case with the FERC in March 1997. Effective November 1997 NYSEG began charging its filed rate, which was accepted by the FERC subject to refund based on a FERC final order. In August 2000 the FERC issued an order in NYSEG's transmission rate case that increased NYSEG's transmission rates. The new rates, however, were lower than the rates in NYSEG's filed rate case, which it began collecting in November 1997 subject to refund. Therefore, NYSEG refunded $14 million, which included interest, to customers. On September 17, 2000, NYSEG filed a petition for rehearing with the FERC that states why FERC inappropriately excluded certain expenses from its calculation. FERC has yet to rule on the request for rehearing.

On July 2, 2001, as supplemented October 23, 2001, CMP filed with FERC to increase its local transmission rates, beginning June 1, 2001, to recover increased costs associated with transmission during periods of high demand and other costs. On January 4, 2002, FERC issued an order accepting the filing as supplemented.

CENTRAL MAINE POWER ALTERNATIVE RATE PLAN | In September 2000 the Maine Public Utilities Commission (MPUC) approved CMP's new Alternative Rate Plan (ARP 2000). ARP 2000 provides the vehicle for CMP and the company to share merger synergies with CMP's customers.

ARP 2000 applies only to CMP's state jurisdictional distribution revenue requirement and excludes revenue requirements related to stranded costs and transmission services. Recovery of stranded costs, primarily over-market nonutility generation (NUG) contracts, 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.

In December 2000 an appeal was filed in the Maine Supreme Judicial Court by the Industrial Energy Consumer Group (IECG) arguing that the MPUC order in CMP's ARP 2000, in certain respects, was unlawful. On July 18, 2001, the court issued a decision affirming the MPUC's ARP 2000 order.

MPUC DELIVERY PRICE DECISION | In March 2001, in response to price increases resulting from higher energy prices, the MPUC reduced CMP's delivery prices for certain medium and large customer classes by 0.8 cent per kilowatt-hour, effective April 15, 2001, through February 28, 2002. Earnings were not, however, affected by this price reduction of approximately $30 million, because the MPUC permitted CMP to amortize a corresponding amount into revenues from a gain recorded by CMP on the sale of its nonnuclear generation assets.

On April 5, 2001, the IECG filed a motion for reconsideration of the MPUC's decision to reduce CMP's delivery prices for certain medium and large customer classes by 0.8 cent per kilowatt-hour. The IECG requested an increase in the price reduction from 0.8 cent to 1.0 cent per kilowatt-hour for all medium and large customer classes. As a result of this motion, the MPUC issued an order dated May 3, 2001, that retained the price reduction at 0.8 cent per kilowatt-hour and extended it to more, but not all, medium and large customer classes for the period April 15, 2001, through February 28, 2002. Earnings were not affected by this MPUC order because the resulting additional decrease of approximately $4 million was offset by amortizing a corresponding amount into revenues from CMP's gain on sale of generation assets account.

On December 21, 2001, the MPUC approved continuation of a 0.45 cent per kilowatt-hour price reduction for certain large customer classes for the period March 1, 2002, through February 28, 2003. The resulting revenue reduction, estimated at $7 million, will continue to be offset by amortizing amounts from CMP's gain on sale of generation assets account.

CENTRAL MAINE POWER ELECTRICITY SUPPLY RESPONSIBILITY | Under Maine Law adopted in 1997 CMP was mandated to sell its generation assets and relinquish its supply responsibilities. However, 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.

On September 18, 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. On January 14, 2002, the MPUC chose Select Energy, Inc. as the new supplier of standard-offer electricity to all other CMP commercial customers and all CMP industrial customers for a one-year period beginning March 1, 2002.

MPUC STRANDED COST PROCEEDINGS | On December 21, 2001, the MPUC approved a stipulation among CMP, the Office of the Public Advocate and the IECG settling all issues related to the setting of CMP's stranded cost revenue requirement for the period March 1, 2002, through February 28, 2005. On January 15, 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 on-going 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 remaining nondivested generating resources and amortization of amounts from CMP's gain on sale of generation assets account.

NYSEG ELECTRIC RATE SETTLEMENT | On January 15, 2002, the company, NYSEG, RGS Energy, Rochester Gas and Electric Corporation (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 reached settlement on both a new five-year NYSEG electric rate plan, which extends through December 31, 2006, and Energy East's merger with RGS Energy. The NYPSC approved the joint proposal on February 27, 2002. The joint proposal supersedes NYSEG's 1998 electric rate and restructuring agreement and the NYPSC Order issued January 10, 2002, regarding temporary rates for NYSEG's electric customers. The joint proposal also provides for the discontinuance of several outstanding NYSEG proceedings, including a proceeding regarding the refunding of state income taxes for calendar years 2000 and 2001. (See New York State Energy Taxes.) NYSEG's and the company's earnings will be lower in 2002 (one year earlier than expected) as a result of the joint proposal because NYSEG's electric rates now reflect the sale of generation assets that was completed in 1999.

Other significant provisions of the joint proposal include:

- A $205 million annualized electric revenue reduction for NYSEG customers commencing March 1, 2002, which amounts 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 will be funded with the partial amortization of an asset sale gain account created by NYSEG's sale in 2001 of its interest in NMP2. The remainder of the asset sale gain account will be used to offset uncontrollable costs that arise during the term of the rate plan. At the end of the rate plan, any remaining balance will be returned to customers in a manner to be determined by the NYPSC. (See Note 9 to the Consolidated Financial Statements.)
- Provisions for the sharing of electric and gas merger synergies between customers and shareholders for both NYSEG and RG&E.
- 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 will use the lower of its actual equity ratio or a 45% equity ratio, which approximates $700 million.
- Beginning in 2003 four competitive supply options will be available to NYSEG's electric customers for two periods of two years (2003 through 2004 and 2005 through 2006): 1) a bundled rate option that combines delivery and supply service at a fixed price; 2) fixed-price delivery service from NYSEG and the ability to purchase electricity supply from an alternative energy company; 3) NYSEG-provided delivery and supply service with delivery service fixed and a pass-through of market prices; and 4) bundled delivery and supply fixed-price service from NYSEG with the ability to switch to an alternative energy supplier and receive a market-based backout. Customers will also pay nonbypassable wires charges.
- Over the term of the plan uncontrollable costs are recoverable through the use of funds in the asset sale gain account.
- Continued economic development, customer service and reliability programs.

NEW YORK STATE ENERGY TAXES | New York State legislation in 2000 included major changes to the taxation of electric and natural gas companies. Those changes included, among others, the repeal of certain gross receipts taxes and the imposition of a net income tax effective January 1, 2000. On June 28, 2001, the NYPSC issued an order concerning the ratemaking treatment related to the implementation of those tax changes, placing certain limits on the recovery of such taxes. NYSEG had previously deferred the excess tax created by the early imposition of the income tax before the repeal of the gross receipts taxes. Subsequently, NYSEG was directed to refund to electric customers approximately $13 million, beginning January 1, 2002, representing the alleged overcollection of state taxes during calendar year 2000. The refunding of these taxes is no longer applicable as it is superseded by the new NYSEG electric rate settlement. (See NYSEG Electric Rate Settlement.)

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 2001 this cumulative overpayment was more than $148 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 is still pending before the court.

NYSEG and CMP together expensed approximately $593 million for NUG power in 2001. They estimate that their purchases will total $637 million in 2002, $651 million in 2003, $672 million in 2004, $677 million in 2005 and $623 million in 2006. NYSEG and CMP continue to seek ways to provide relief to their customers from above-market NUG contracts that state regulations ordered NYSEG and CMP to sign, and which averaged 8.24 cents per kilowatt-hour for 2001. Recovery of these NUG costs is provided for in NYSEG's and CMP's current regulatory plans. (See Note 7 to the Consolidated Financial Statements.)

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 ALLIANCE | Four of Energy East's natural gas companies: NYSEG, The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (Berkshire Gas), entered into a one-year strategic alliance agreement with BP Energy Company effective March 30, 2001, for the acquisition, optimization and management of natural gas supply, including price risk management. The alliance provides the companies with greater supply flexibility and enhances the benefits of a larger natural gas portfolio as a result of Energy East's mergers that were completed in 2000. The alliance 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 alliance agreement with BP Energy expires on March 31, 2002. On December 21, 2001, four of Energy East's natural gas companies issued a request for a proposal to various suppliers, producers and marketers seeking to explore alternatives to replace the expiring contract. RG&E, a subsidiary of RGS Energy, issued a similar request for a proposal.

NYSEG NATURAL GAS RATE FILINGS | On October 19, 2001, NYSEG filed a natural gas rate case with the NYPSC. NYSEG proposes to unbundle delivery and gas supply charges, increase delivery rates by approximately $23 million, implement a gas adjustment clause, a weather normalization clause and a delivery adjustment clause, and continue the promotion of retail choice for all customers. The filing proposes to change the existing residential rate structure from fully bundled fixed sales service rates to fixed delivery rates and floating gas supply charges. Similarly, for nonresidential customers, delivery charges will be reset and fixed, while gas supply charges will float with market changes. NYSEG also proposes rate design changes by rate area and service class to more closely match NYSEG's cost to serve.

NYSEG's natural gas prices have been frozen for six years. The requested increases will allow NYSEG to recover and earn a return on over $250 million in infrastructure improvements since 1995, and ensure the continued safety and reliability of its natural gas delivery system. The rate plan is premised on an 11.5% return on equity and a 48% equity ratio. The new rates would become effective October 2002.

NYSEG's natural gas business is currently operating under a four-year rate plan that ends September 30, 2002. The plan continues NYSEG's natural gas rate freeze for residential sales customers and provides pricing options for nonresidential customers.

On October 29, 2001, NYSEG filed a petition with the NYPSC for authorization to defer the difference between natural gas costs embedded in its residential gas sales rates and actual gas costs incurred for residential sales customers during the period November 1, 2001, through September 30, 2002. The petition is the result of sustained unanticipated high wholesale commodity costs. (See Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk.) The petition also addresses the direction NYSEG received to refund to natural gas customers approximately $1 million beginning January 1, 2002, representing the alleged overcollection of state taxes during calendar year 2000. NYSEG anticipates the NYPSC will issue its decision in the first quarter of 2002.

CONNECTICUT REGULATORY PROCEEDINGS | In January 2001 the Connecticut Office of Consumer Counsel (OCC) filed an appeal in State Superior Court arguing that the Connecticut Department of Public Utility Control's (DPUC) order in December 2000 approving the SCG multi-year incentive rate plan (IRP) was unlawful. On March 30, 2001, the OCC filed a Motion to Stay the implementation of the DPUC's order, but the court denied the motion on June 18, 2001.

In May 2001 the DPUC issued a decision for CNG's IRP, approving a four-year term and replacing the proposed sharing in returns on equity with a graduated sharing in returns on equity in excess of 10.8%. The excess over 10.8% would be shared among shareholders and customers as follows: first 2% 75/25, next 4% 50/50 and over 6% 25/75. Performance and service measures were also adopted. After-tax merger-related natural gas cost savings are to be shared 50/50. On June 20, 2001, the OCC filed an appeal in Superior Court, arguing that the IRP approved by the DPUC for CNG was unlawful.

In August 2001 the court appeals for SCG's and CNG's IRPs were combined.

On October 23, 2001, SCG and CNG reached a settlement with the OCC, resolving numerous outstanding regulatory and legal proceedings. The settlement was also endorsed by Prosecutorial Staff of the DPUC. 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 over-earnings at SCG and CNG, and the above court appeal of the approved IRPs for SCG and CNG.

The settlement provides rate reductions of $1.5 million for SCG and $0.5 million for CNG, effective October 1, 2001. The settlement extends the approved IRPs for an additional year through September 2005 and maintains an earnings sharing mechanism that generally shares earnings above the authorized returns on equity 50/50 between shareholders and customers. In addition, the settlement 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 50/50 between customers and shareholders, with the shareholder portion recovered through the PGA.

The settlement was filed with the DPUC on October 25, 2001, and hearings were held in December 2001. SCG and CNG received a final decision from the DPUC approving the settlement on February 22, 2002.

BERKSHIRE GAS RATE INCREASE | On July 17, 2001, Berkshire Gas filed a petition with the Massachusetts Department of Telecommunications and Energy (DTE) for a rate increase that would add about $5 million, or 9%, to Berkshire Gas' total annual revenues. On January 31, 2002, the DTE approved a rate increase of $2.3 million, or 4.5%, on total annual revenues. The DTE's approval included Berkshire's proposal for a 10-year incentive-based rate plan with a mid-period 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's 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's proposal for service quality enhancements will be addressed in another proceeding. The new rates became effective February 1, 2002. On February 20, 2002, Berkshire filed a motion for clarification and recalculation of certain items in the DTE's final decision.

NYPSC COLLABORATIVE ON THE 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 on November 9, 2001, directing the development of embedded cost of service studies. Certain of these objectives are to be implemented in connection with NYSEG's electric rate settlement.

Other Businesses

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

CAYUGA ENERGY GENERATING PLANT | On May 29, 2001, Cayuga Energy, a wholly-owned subsidiary of the company, and PEI Power Corporation announced that their newly-constructed peaking-power plant in Archbald, Pennsylvania, which is an exempt wholesale generator, was in service and selling electricity to the mid-Atlantic market. In July 2000 the two companies announced the formation of a joint venture company, PEI Power II, L.L.C., to build and operate the 44-megawatt natural gas-fired plant. Cayuga Energy owns 50.1% of the plant and manages fuel procurement and electricity sales. PEI Power Corporation owns the remaining 49.9% and is responsible for the plant's daily operation.

NATURAL GAS STORAGE FACILITY | On August 3, 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 expects to begin operating the facility in November 2002. The storage facility will be linked to interstate pipelines, have a projected working gas capacity of 300,000 dekatherms (dth) and be capable of delivering up to 50,000 dth a day. In August 2001 SLSI filed with the FERC for authority to use the new facility to supply firm and interruptible natural gas storage services at market-based rates. On February 14, 2002, FERC granted the requested authorizations. State and local permits are also being sought from the appropriate agencies.

MAINE NATURAL GAS | In June 2001 Maine Natural Gas began construction of a new natural gas distribution system to serve the towns of Brunswick and Topsham, Maine. It began serving natural gas to certain larger customers in November 2001, and after further construction, expects to begin serving residential and commercial customers in mid-2002.

Other Matters

Accounting Issues

STATEMENT 71 | Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation, allows companies that meet certain criteria to capitalize, as regulatory assets, incurred 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.

Although 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, 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. NYSEG and CMP may also have to record as a loss an estimated $1.1 billion and $0.9 billion, respectively, on a present value basis at December 31, 2001, of above-market costs on their power purchase contracts with NUGs. Those costs are currently being recovered in rates.

STATEMENTS 141 AND 142 | The Financial Accounting Standards Board (FASB), in July 2001, issued Statement of Financial Accounting Standards No. 141, Business Combinations and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets. (See Note 1 to the Consolidated Financial Statements.)

Investing and Financing Activities

The company's financial strength provides the flexibility required to compete in the developing competitive energy market and continue expanding its products and services, including its energy infrastructure, in the Northeast.

INVESTING ACTIVITIES | Capital spending totaled $223 million in 2001, $168 million in 2000 and $83 million in 1999, including nuclear fuel, but not including the company's four merger transactions in 2000. (See Note 2 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.

Capital spending, excluding the RGS merger transaction, is projected to be $223 million in 2002. It is expected to be paid for with internally generated funds and will be primarily for the same purposes described above. (See Note 7 to the Consolidated Financial Statements.)

In August 2001 the company provided a $100 million equity contribution to NYSEG. The contribution was used by NYSEG to help repay $152 million in debt in connection with the termination of its sale of accounts receivable program.

FINANCING ACTIVITIES | (See Note 4 to the Consolidated Financial Statements.) The company repurchased 1.3 million shares of its common stock at an average price of $18.45 per share during 2001. The company expects to repurchase shares on an opportunistic basis in the future. The amount of future repurchases will depend on expected cash flows, alternative uses of cash, and overall economic and market conditions.

The company raised its common stock dividend 4% in January 2002 to a new annual rate of 96 cents per share.

In August 2001 the company began issuing new common shares through its Dividend Reinvestment and Stock Purchase Plan, rather than purchasing them on the open market. The company expects to issue approximately one million shares per year under this plan.

The company and its subsidiaries have credit agreements with various expiration dates in 2002. The agreements provided for maximum borrowings of $755 million at December 31, 2001, and $724 million at December 31, 2000.

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 $173 million of such short-term debt outstanding at December 31, 2001, and $419 million outstanding at December 31, 2000. The weighted-average interest rate on short-term debt was 2.6% at December 31, 2001, and 7.7% at December 31, 2000.

On May 31, 2001, the company filed a shelf registration statement with the SEC to sell up to $1 billion in an unspecified combination of debt and trust preferred securities, of which $405 million is currently available. The company plans to use the net proceeds from this shelf registration to fund the cash portion of the consideration for the pending merger with RGS Energy. (See Energy East Corporation and RGS Energy Merger Agreement.) The company may also use a portion of the proceeds for general corporate purposes, such as short-term debt reduction, repurchases of securities and to fund equity contributions to subsidiaries.

In July 2001 a business trust subsidiary issued $345 million of 8 1/4% Capital Securities. (See Energy East Corporation and RGS Energy Merger Agreement.) The proceeds were used to purchase Energy East's 8 1/4% junior subordinated debt securities. Payments on such debt securities will be used by the trust to pay dividends on the Capital Securities.

In July 2001 the company entered into a fixed-to-floating interest rate swap on the company's 8.05% debt series due November 2010. The company receives a fixed rate of 8.05% and will pay a rate based on the six month London Interbank Offered Rate plus 1.875%, on a notional amount of $200 million through November 2010.

In November 2001 the company issued $250 million of 5.75% five-year notes due November 2006. The proceeds were used to fund the $100 million equity contribution to NYSEG previously noted and the balance will be used to fund the RGS Energy merger.

Additional financing needed to complete the RGS Energy merger, estimated at $400 million, is expected to be issued just prior to completion of the merger. Through financial instruments entered into in August 2001, the company has locked in the treasury rate component of that financing at an average rate of 5.05%.

CMP issued the following Series E Medium Term Notes, the proceeds of which were used to redeem short-term debt and for general corporate purposes:

- On January 30, 2001, $25 million of 6.67% due January 2006.
- On June 20, 2001, $10 million of 7% due June 2011.
- On July 16, 2001, $5 million of 6 7/8% due July 2008.
- On July 23, 2001, $20 million of 6 3/8% due July 2005.
- On August 14, 2001, $15 million of 7% due August 2011.

On December 11, 2001, CMP issued $19.5 million of 5 3/8% Pollution Control Revenue Refunding Bonds due May 2014. The proceeds were used to refund $19.5 million of Floating/Fixed Rate Pollution Control Revenue Bonds.

On September 28, 2001, SCG issued $30 million of 6.59% Secured Medium-Term Notes due September 2011. The proceeds were used to repay short-term debt and for working capital purposes.

Quantitative and Qualitative Disclosures About Market Risk

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

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

INTEREST RATE RISK | The company is exposed to risk resulting from interest rate changes on its variable-rate debt and commercial paper. The company and its subsidiaries use interest rate swap agreements to manage the risk of increases in such variable rate issues and to maintain desired fixed-to-floating rate ratios. Amounts paid and received under those agreements are recorded as adjustments to the interest expense of the specific debt issues. The company estimates that a 1% change in average interest rates would change its annual interest expense for variable rate debt by about $5 million. (See Notes 4 and 11 to the Consolidated Financial Statements.)

The company occasionally uses financial instruments to lock in the treasury rate component of future financings.

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

While 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. On September 18, 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. On January 14, 2002, the MPUC chose Select Energy, Inc. as the new supplier of standard-offer electricity to all other CMP commercial customers and all CMP industrial customers for a one-year period beginning March 1, 2002.

CNG, SCG and Berkshire Gas all have purchased gas adjustment clauses. (See Natural Gas Delivery Business, Connecticut Regulatory Proceedings.) Under its current rate and restructuring plans, NYSEG is subject to the effect of market fluctuations in the price of natural gas and electricity purchased. NYSEG's natural gas exposure is limited to purchases for residential customers because it is allowed to pass through increases in the market price of natural gas to nonresidential customers. NYSEG has filed for a gas adjustment clause for residential customers that would become effective in October 2002. NYSEG has also filed for authorization to defer the difference between natural gas costs embedded in its residential gas sales rates and actual gas costs incurred for residential customers during the period November 1, 2001, through September 30, 2002. (See NYSEG Natural Gas Rate Filings.)

NYSEG uses natural gas futures and options contracts to manage its exposure to fluctuations in natural gas commodity prices. Such contracts allow NYSEG to fix margins on sales of natural gas. The cost or benefit of natural gas futures and options contracts is included in the commodity cost when the related sales commitments are fulfilled.

NYSEG has hedged approximately 81% of its expected residential natural gas load through September 2002 with gas in storage, futures and options contracts. For its remaining unhedged positions through September 2002, a $1.00 per dekatherm change in the cost of natural gas would change natural gas costs by about $4 million.

NYSEG uses electricity contracts and contracts for differences (CFDs), which are financial contracts with features similar to commodity swap agreements, to manage against fluctuations in the cost of electricity. Those contracts allow NYSEG to fix margins on the majority of its retail electricity sales. The cost or benefit of those contracts is included in the amount expensed for electricity purchased when the electricity is sold. NYSEG has CFDs, generation and other electricity contracts, which provide for 96% of its expected electric energy requirements for 2002, 69% for 2003 and 65% for 2004.

NYSEG uses a cash flow at risk (CFAR) calculation to measure price risk for electricity. NYSEG estimates the CFAR using a closed form methodology. The CFAR indicates the amount by which the fair value of NYSEG's net position could vary from its current level over a 12-month period, with a 97.5% certainty, assuming all unhedged positions during that period are filled in the market. At year end, excluding the reconciliation provided for in NYSEG's electric rate settlement, the CFAR for electricity requirements was approximately $10 million for the next 12-month period. NYSEG's electric rate settlement provides for a reconciliation and true-up of certain actual power supply costs during 2002, therefore the supply cost risk for 2002 will be substantially eliminated. (See NYSEG Electric Rate Settlement.) The value at risk for the year ended December 31, 2001, was: average – $1.5 million, high – $2.3 million and low – $0.9 million.

OTHER MARKET RISK | The company's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates could cause the company to recognize increased or decreased pension income or expense. (See Note 14 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 could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others: the deregulation and continued regulatory unbundling of a vertically integrated industry; the company's ability to compete in the rapidly changing and increasingly competitive electricity and natural gas utility markets; regulatory uncertainty in a politically charged environment of fluctuating energy prices; operation of the New York Independent System Operator and ISO New England, Inc.; the operation of a regional transmission organization; the ability to control nonutility generator and other costs; changes in fuel supply or cost and the success of strategies to satisfy power requirements now that all of the company's coal-fired generation assets have been sold; the company's ability to expand its products and services, including its energy infrastructure in the Northeast; its ability to integrate the operations of Connecticut Energy Corporation (CNE), CMP Group, Inc., CTG Resources, Inc., Berkshire Energy Resources and RGS Energy with its operations; market risk; the ability to obtain adequate and timely rate relief; nuclear, terrorist or environmental incidents; legal or administrative proceedings; changes in the cost or availability of capital; growth in the areas in which the company is doing business; weather variations affecting customer energy usage; and other considerations that may be disclosed from time to time in the company's publicly disseminated documents and filings. The company undertakes no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

Results of Operations

Due to the mergers completed in 2000 – CNE in February 2000 and CMP Group, CTG Resources and Berkshire Energy in September 2000 – the company's results of operations for 2001 include those merged companies. Results of operations for 2000 include CNE beginning with February 2000 and include CMP Group, CTG Resources and Berkshire Energy beginning with September 2000.

(Thousands, except per share amounts)	**2001**	2000	1999	2001 over 2000 Change	2000 over 1999 Change
Operating Revenues	**$3,759,787**	$2,959,520	$2,278,608	27%	30%
Operating Income	**$636,888**	$513,921	$562,583	24%	(9%)
Income Before Extraordinary Item	**$187,607**	$236,679	$236,317	(21%)	–
Extraordinary Loss, Net of Tax	**–**	$1,645	$17,566	(100%)	(91%)
Net Income	**$187,607**	$235,034	$218,751	(20%)	7%
Average Common Shares Outstanding	**116,708**	114,213	116,316	2%	(2%)
Earnings Per Share Before Extraordinary Loss, basic and diluted	**$1.61**	$2.07	$2.03	(22%)	2%
Earnings Per Share, basic and diluted	**$1.61**	$2.06	$1.88	(22%)	10%
Dividends Paid Per Share	**$.92**	$.88	$.84	5%	5%

Earnings Per Share

The company's earnings per share for 2001 were $2.00 compared to $2.04 for 2000, excluding certain one-time items. Those items include a writedown of 39 cents to CMP Group's investment in NEON Communications, Inc. in 2001 (See Note 11 to the Consolidated Financial Statements), and in 2000 a nonrecurring loss of four cents from the sale of XENERGY, Inc., a nonrecurring benefit of seven cents from the sale of the company's coal-fired generation assets and an extraordinary loss from the early retirement of debt of one cent. The decrease was primarily due to lower electric and natural gas deliveries due to warmer weather and reduced electric transmission revenues. Those decreases were partially offset by cost control efforts and earnings from the merged companies.

The company's 2000 earnings per share were $2.04 compared to $1.91 for 1999, excluding a nonrecurring loss of four cents from the sale of XENERGY, Inc. in 2000, nonrecurring benefits of seven cents in 2000 and 12 cents in 1999 from the sale of the company's coal-fired generation assets and extraordinary losses from the early retirement of debt of one cent in 2000 and 15 cents in 1999. The increase was primarily due to higher retail electric and natural gas deliveries for NYSEG, cost control efforts, earnings from the merged companies and fewer shares outstanding due to the share repurchase program. Those increases were partially offset by higher costs of energy net of transmission revenues, lower wholesale electric deliveries as a result of the sale of the company's coal-fired generation assets, and lower retail electric prices.

Other Items

Other income and deductions decreased in 2001 and 2000 primarily due to lower investment income after the net proceeds from the sale of the company's coal-fired generation assets were used to finance the company's merger transactions, partially offset by other income associated with the merged companies.

Interest charges increased in 2001 and 2000 primarily due to additional borrowings to finance the company's merger transactions, including the RGS merger, and interest charges associated with the merged companies.

Preferred stock dividends increased in 2001 primarily due to the issuance of trust preferred securities in July 2001 and preferred dividends associated with the merged companies. Preferred stock dividends decreased in 2000 primarily due to the redemptions and repurchases of preferred stock in 1999.

Operating Results for the Electric Delivery Business

(Thousands)	**2001**	2000	1999	2001 over 2000 Change	2000 over 1999 Change
Deliveries – Megawatt-hours					
Retail	**23,238**	17,133	13,843	36%	24%
Wholesale	**6,048**	6,214	10,978	(3%)	(43%)
Operating Revenues	**$2,504,896**	$2,023,610	$1,889,318	24%	7%
Operating Expenses	**$1,951,475**	$1,540,953	$1,373,674	27%	12%
Operating Income	**$553,421**	$482,657	$515,644	15%	(6%)

OPERATING REVENUES | Operating revenues for 2001 increased $481 million compared to 2000 primarily due to the first full year of CMP's delivery revenues. Those increases were partially offset by lower deliveries because of warmer weather and by reduced transmission revenues.

The $134 million increase in operating revenues for 2000 is due to the addition of CMP's delivery revenues beginning September 1, 2000, higher transmission revenues, and higher retail deliveries due to colder weather in 2000. That increase was partially offset by lower wholesale deliveries as a result of the sale of the company's coal-fired generation assets in 1999 and lower retail prices.

OPERATING EXPENSES | Operating expenses for 2001 increased $411 million primarily due to the first full year of CMP's operating costs. That increase was partially offset by lower purchased power costs due to lower deliveries and by cost control efforts.

Operating expenses for 2000 increased $54 million, excluding a $113 million benefit in 1999 from the sale of the company's coal-fired generation assets, net of the writeoff of NMP2. That increase was due to the addition of CMP's purchases for retail deliveries and operating costs beginning September 1, 2000, and higher purchase costs of electricity primarily due to higher than anticipated ancillary services costs associated with the NYISO and higher market prices. Those increases were partially offset by a reduction in operating expenses because of the sale of the company's coal-fired generation assets and a related reduction in amortization of NMP2 and by cost control efforts.

Operating Results for the Natural Gas Delivery Business

(Thousands)	**2001**	2000	1999	2001 over 2000 Change	2000 over 1999 Change
Deliveries – Dekatherms					
Retail	**148,000**	108,139	59,346	37%	82%
Wholesale	**9,298**	10,674	8,617	(13%)	24%
Operating Revenues	**$1,026,124**	$772,131	$331,745	33%	133%
Operating Expenses	**$936,606**	$699,402	$269,551	34%	159%
Operating Income	**$89,518**	$72,729	$62,194	23%	17%

OPERATING REVENUES | For 2001, operating revenues increased $254 million primarily due to the first full year of revenues from SCG, CNG and Berkshire Gas. Those increases were partially offset by lower deliveries due to warmer weather.

Operating revenues for 2000 increased $440 million primarily due to the addition of revenues from SCG beginning February 1, 2000, and CNG and Berkshire Gas beginning September 1, 2000. The recovery of increased gas costs for nonresidential deliveries and higher deliveries due to colder weather also added to operating revenues.

OPERATING EXPENSES | Operating expenses for 2001 increased $237 million primarily due to the first full year of natural gas purchases and operating costs for SCG, CNG and Berkshire Gas. Those increases were partially offset by reduced purchased natural gas costs due to lower deliveries and by cost control efforts.

Operating expenses for 2000 increased $430 million primarily due to the addition of natural gas purchases and operating costs associated with the three merged gas companies – SCG, CNG and Berkshire Gas, and higher retail purchased gas costs caused by higher market prices and higher deliveries.

Consolidated Statements of Income

Year Ended December 31	2001	2000	1999
(Thousands, except per share amounts)			
Operating Revenues			
Sales and services	**$3,759,787**	$2,959,520	$2,278,608
Operating Expenses			
Electricity purchased and fuel used in generation	**1,334,507**	1,073,728	905,367
Natural gas purchased	**694,038**	496,509	186,722
Other operating expenses	**570,186**	435,965	312,129
Maintenance	**139,395**	108,106	85,849
Depreciation and amortization	**204,281**	165,524	648,970
Other taxes	**192,772**	165,767	179,028
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	**3,122,899**	2,445,599	1,716,025
Operating Income	**636,888**	513,921	562,583
Writedown of Investment	**78,422**	–	–
Other (Income) and Deductions	**(15,003)**	(32,906)	(39,597)
Interest Charges, Net	**217,028**	152,503	132,908
Preferred Stock Dividends of Subsidiaries	**14,455**	963	2,706
Income Before Income Taxes	**341,986**	393,361	466,566
Income Taxes	**154,379**	156,682	230,249
Income Before Extraordinary Item	**187,607**	236,679	236,317
Extraordinary Loss on Early Extinguishment of Debt, Net of Income Tax Benefit of $1,121 for 2000 and $9,458 for 1999	**–**	1,645	17,566
Net Income	**$187,607**	$235,034	$218,751
Earnings Per Share, basic and diluted	**$1.61**	$2.06	$1.88
Average Common Shares Outstanding	**116,708**	114,213	116,316

The notes on pages 40 through 55 are an integral part of the financial statements.

Consolidated Balance Sheets

December 31	2001	2000
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$437,014**	$143,626
Special deposits	**1,555**	21,516
Accounts receivable, net	**563,796**	536,280
Fuel, at average cost	**92,234**	65,496
Materials and supplies, at average cost	**21,466**	22,759
Accumulated deferred income tax benefits, net	**4,170**	5,007
Prepayments and other current assets	**54,601**	57,720
Total Current Assets	**1,174,836**	852,404
Utility Plant, at Original Cost		
Electric	**3,874,972**	4,784,312
Natural gas	**1,771,636**	1,665,386
Common	**213,362**	220,124
	5,859,970	6,669,822
Less *accumulated depreciation*	**2,270,516**	3,096,283
Net Utility Plant in Service	**3,589,454**	3,573,539
Construction work in progress	**36,978**	59,389
Total Utility Plant	**3,626,432**	3,632,928
Other Property and Investments, Net	**216,556**	259,708
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**199,797**	234,929
Unfunded future income taxes	**164,657**	184,570
Unamortized loss on debt reacquisitions	**53,965**	58,848
Demand-side management program costs	**18,137**	48,929
Environmental remediation costs	**85,835**	78,406
Other	**248,738**	241,396
Total regulatory assets	**771,129**	847,078
Other assets		
Goodwill, net	**897,807**	952,358
Prepaid pension benefits	**435,901**	350,038
Other	**146,571**	119,214
Total other assets	**1,480,279**	1,421,610
Total Regulatory and Other Assets	**2,251,408**	2,268,688
Total Assets	**$7,269,232**	$7,013,728

The notes on pages 40 through 55 are an integral part of the financial statements.

Consolidated Balance Sheets

December 31 (Thousands)	2001	2000
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$225,678**	$25,285
Notes payable	**173,383**	418,995
Accounts payable and accrued liabilities	**224,150**	345,424
Interest accrued	**36,183**	35,309
Taxes accrued	**7,020**	–
Other	**142,926**	211,784
Total Current Liabilities	**809,340**	1,036,797
Regulatory and Other Liabilities		
Regulatory liabilities		
Deferred income taxes	**157,196**	166,894
Gain on sale of generation assets	**251,254**	232,041
Pension benefits	**52,642**	96,514
Other	**68,879**	76,813
Total regulatory liabilities	**529,971**	572,262
Other liabilities		
Deferred income taxes	**461,600**	457,495
Nuclear plant obligations	**199,797**	234,929
Other postretirement benefits	**282,791**	279,864
Environmental remediation costs	**102,930**	91,811
Other	**241,975**	233,910
Total other liabilities	**1,289,093**	1,298,009
Total Regulatory and Other Liabilities	**1,819,064**	1,870,271
Long-term debt	**2,471,278**	2,346,814
Total Liabilities	**5,099,682**	5,253,882
Commitments	**–**	–
Preferred Stock of Subsidiaries		
Company-obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures	**345,000**	–
Preferred stock redeemable solely at the option of subsidiaries	**43,373**	43,324
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 116,718 shares outstanding at December 31, 2001, and 117,656 shares outstanding at December 31, 2000)	**1,182**	1,191
Capital in excess of par value	**842,989**	871,078
Retained earnings	**998,281**	918,016
Accumulated other comprehensive income (loss)	**(22,335)**	(34,823)
Treasury stock, at cost (1,418 shares at December 31, 2001 and 2000)	**(38,940)**	(38,940)
Total Common Stock Equity	**1,781,177**	1,716,522
Total Liabilities and Stockholders' Equity	**$7,269,232**	$7,013,728

The notes on pages 40 through 55 are an integral part of the financial statements.

Consolidated Statements of Cash Flows

Year Ended December 31	2001	2000	1999
(Thousands)			
Operating Activities			
Net income	**$187,607**	$235,034	$218,751
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	**204,281**	165,524	648,970
Income taxes and investment tax credits deferred, net	**3,089**	27,097	(432,774)
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
Pension income	**(78,015)**	(65,659)	(77,559)
Writedown of investment	**78,422**	–	–
Extraordinary loss, net of tax	**–**	1,645	17,566
Changes in current operating assets and liabilities			
Accounts receivable	**124,484**	(87,301)	(8,671)
Sale of accounts receivable program	**(152,000)**	–	–
Inventory	**(25,445)**	(13,376)	58,504
Accounts payable and accrued liabilities	**(121,274)**	(4,076)	19,219
Taxes accrued	**7,020**	668	14,145
Other current liabilities	**(68,858)**	41,325	(16,021)
Other, net	**(11,698)**	(62,887)	28,582
Net Cash Provided by (Used in) Operating Activities	**135,333**	237,994	(131,328)
Investing Activities			
Sale of generation assets	**59,441**	–	1,850,000
Acquisitions, net of cash acquired	**–**	(1,442,717)	–
Utility plant additions	**(208,580)**	(155,704)	(69,853)
Temporary investments, net	**–**	1,017,609	(760,996)
Other property and investments	**(12,519)**	8,711	(24,664)
Other	**22,619**	(12,741)	2,560
Net Cash (Used in) Provided by Investing Activities	**(139,039)**	(584,842)	997,047
Financing Activities			
Issuance of common stock	**7,201**	–	–
Repurchase of common stock	**(24,116)**	(163,493)	(396,915)
Issuance of mandatorily redeemable trust preferred securities	**345,000**	–	–
Treasury stock acquired, net	**–**	–	(31,373)
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	**(1,890)**	(134,947)	(329,719)
Long-term note issuances	**355,553**	601,114	10,185
Long-term note retirements	**(31,700)**	(21,346)	(35,374)
Notes payable, net	**(245,612)**	191,946	84,940
Dividends on common stock	**(107,342)**	(99,606)	(98,725)
Net Cash Provided by (Used in) Financing Activities	**297,094**	373,668	(796,981)
Net Increase in Cash and Cash Equivalents	**293,388**	26,820	68,738
Cash and Cash Equivalents, Beginning of Year	**143,626**	116,806	48,068
Cash and Cash Equivalents, End of Year	**$437,014**	$143,626	$116,806

The notes on pages 40 through 55 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, 1999	125,894	$631	$1,057,904	$662,562	–	$(7,611)	$1,713,486
Net income				218,751			218,751
Other comprehensive income, net of tax					$(1,681)		(1,681)
Comprehensive income							217,070
Common stock dividends declared ($.84 per share)				(98,725)			(98,725)
Two-for-one stock split		598	(598)				–
Common stock repurchased	(15,324)	(121)	(396,794)				(396,915)
Treasury stock transactions, net	(1,227)		13			(31,386)	(31,373)
Amortization of capital stock issue expense			411				411
Balance, December 31, 1999	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

The notes on pages 40 through 55 are an integral part of the financial statements.

Note 1 Significant Accounting Policies

ACCOUNTS RECEIVABLE | Accounts receivable on the consolidated balance sheets are shown net of an allowance for doubtful accounts of $18 million at December 31, 2001, and $19 million at December 31, 2000. Bad debt expense was $34 million in 2001, which includes the merged companies for a full year for the first time, $24 million in 2000, and $12 million in 1999.

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. At December 31, 2000, accounts receivable on the consolidated balance sheets are shown net of $152 million of interests in accounts receivable sold. All fees related to the sale of accounts receivable through March 31, 2001, are included in other income and deductions on the consolidated statements of income and amounted to approximately $2 million in 2001, $10 million in 2000 and $9 million in 1999. Fees related to the agreement beginning April 1, 2001, which were approximately $3 million, are included in interest expense on the consolidated statements of income.

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	**2001**	2000	1999
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	**$208,431**	$132,009	$122,578
Income taxes (2001 includes $15,081 and 1999 includes $548,201 related to gains on sales of generation assets)	**$113,274**	$154,108	$646,715
Acquisitions:			
Fair value of assets acquired	**–**	$2,526,971	–
Liabilities assumed	**–**	(689,180)	–
Common stock issued	**–**	(373,708)	–
Cash acquired	**–**	(21,366)	–
Net cash paid for acquisitions	**–**	$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 in service at each operating company. The company's depreciation accruals were equivalent to 3.1% of average depreciable property for 2001, 3.1% for 2000, which was weighted for the effect of the mergers completed in September 2000, and 3.4% for 1999. Amortization expense includes the amortization of certain regulatory assets and the accelerated amortization of NMP2 in 1999 as authorized by the NYPSC. (See Note 8. Sale of Coal-Fired Generation Assets.)

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 was amortized on a straight-line basis over five to 40 years through December 31, 2001. 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 Statements 141 and 142, below.)

INCOME TAXES | The company files a consolidated federal income tax return. 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.

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 2001 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.

RISK MANAGEMENT | The company uses natural gas futures and options contracts to manage its exposure to fluctuations in natural gas commodity prices. Such contracts allow the company to fix margins on sales of natural gas generally expected to occur in 2002. The cost or benefit of natural gas futures and options contracts is included in the commodity cost when the related sales commitments are fulfilled. At December 31, 2001, the company held natural gas futures and options contracts for 15 million dekatherms of natural gas, at an average price of $3.35 per dekatherm, through August 2004.

The company uses electricity contracts, both physical and financial, to manage against fluctuations in the cost of electricity. The contracts allow the company to fix margins on the majority of its retail electricity sales. The cost or benefit of electricity contracts is included in the amount expensed for electricity purchased when the electricity is sold. At December 31, 2001, the company held financial contracts for five million megawatt-hours, at an average price of $30.01 per megawatt-hour, through April 2003.

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

In accordance with the FASB's 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), the company recognizes the fair value of its natural gas options, futures, financial electricity contracts and interest rate agreements as assets or liabilities on the consolidated balance sheets. The company's liability at December 31, 2001, was $32 million. All of these arrangements are designated as cash flow hedging instruments except for the company's $200 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.

As of December 31, 2001, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted transactions is 31 months. The company estimates that losses of $21 million will be reclassified from accumulated other comprehensive income into earnings in 2002, 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 purchase and sale exception in Statement 138.

STATEMENTS 141 AND 142 | The FASB issued Statement 141 and Statement 142 in July 2001. Statement 141 requires that all business combinations be accounted for using the purchase method of accounting. Use of the pooling-of-interests method of accounting for business combinations is prohibited. Statement 141 also addresses the initial recognition and measurement of goodwill and other intangible assets. The provisions of Statement 141 apply to all business combinations that are initiated after June 30, 2001, and to all business combinations accounted for by the purchase method of accounting that are completed after June 30, 2001. Transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method of accounting, may require companies to reclassify certain intangible assets and/or goodwill.

Statement 142 requires that goodwill no longer be amortized, but instead be tested at least annually for impairment using a two-step impairment test. The first step of the goodwill impairment test identifies potential impairment by comparing the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value is greater than the carrying value, then goodwill is not impaired and the second step is not necessary. The second step of the goodwill impairment test is performed if the carrying amount of a reporting unit is greater than its fair value. If the carrying amount of a reporting unit's goodwill is greater than the implied fair value of its goodwill, the excess is to be recognized as an impairment loss.

Statement 142 also requires that a recognized intangible asset with a finite life be amortized over its useful life and be reviewed for impairment, and that a recognized intangible asset with an indefinite life not be amortized until its life is determined to be no longer indefinite. A recognized intangible asset that is not amortized is to be tested for impairment annually, or more frequently if circumstances indicate an asset might be impaired. If the carrying amount of an intangible asset is greater than its fair value, the excess is to be recognized as an impairment loss. The provisions of Statement 142 are effective for fiscal years beginning after December 15, 2001.

The company adopted Statements 141 and 142 as of January 1, 2002, which had the following effects: goodwill valued at an estimated $898 million is no longer being amortized and the expected annual decrease in amortization expense for goodwill is $24 million. Management is still evaluating the additional effects that the adoptions may have, including the possible reclassification of goodwill and/or intangible assets and the need to recognize any transition or impairment losses.

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 Acquisitions of Connecticut Energy, CMP Group, CTG Resources and Berkshire Energy

The company's merger with CNE was completed on February 8, 2000, and its mergers with CMP Group, CTG Resources and Berkshire Energy were completed on September 1, 2000. The four transactions were accounted for using the purchase method. The company's 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.

In each transaction the purchase price was allocated to the assets acquired and liabilities assumed based on values on the date of purchase. The cost in excess of the fair value of the net assets acquired in each transaction was recorded as goodwill and was amortized through December 31, 2001, on a straight-line basis over the estimated useful life. The useful life was determined based on the individual characteristics of each acquired company and the lives ranged from five to 40 years. Goodwill was adjusted over the 12 months following the mergers as actual amounts for the estimated liabilities became known. On January 1, 2002, the company adopted Statements 141 and 142. (See Note 1 – Statements 141 and 142.)

The following pro forma information for the company for the years ended December 31, 2000 and 1999, which is based on unaudited data, gives effect to the company's four mergers as if they had been completed January 1, 1999. This information does not reflect future revenues or cost savings from the mergers and is not indicative of actual results of operations had the mergers occurred at the beginning of the periods presented or of results that may occur in the future.

Year Ended December 31	2000	1999
(Thousands, except per share amounts)		
Revenues	$3,912,475	$3,850,850
Net Income	$253,718	$232,619
Earnings Per Share of Common Stock	$2.11	$1.75

Pro forma adjustments reflected in the amounts presented above include: (1) additional depreciation and amortization related to adjusting the four merged companies' nonutility assets to fair value based on an independent appraisal, (2) amortization of goodwill, (3) elimination of merger costs, (4) lower investment income due to the sale of temporary investments to complete the mergers, (5) interest expense due to the issuance of merger-related debt, (6) adjustments for estimated tax effects of the above adjustments and (7) additional common shares issued in connection with the mergers.

Note 3 Income Taxes

Year Ended December 31 (Thousands)	2001	2000	1999
Current	$147,497	$129,220	$662,512
Deferred, net			
Accelerated depreciation	12,312	628	(379,422)
Pension benefits	30,430	24,051	37,311
Statement 106 postretirement benefits	(4,079)	(11,417)	(6,618)
Demand-side management	(9,295)	(8,335)	(4,300)
Miscellaneous	(20,371)	23,676	(5,505)
ITC	(2,115)	(2,262)	(83,187)
Total	154,379	155,561	220,791
Less amount classified as extraordinary item	–	(1,121)	(9,458)
Total Before Extraordinary Item	$154,379	$156,682	$230,249

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

Year Ended December 31 (Thousands)	2001	2000	1999
Tax expense at statutory rate	$124,754	$137,045	$154,787
Depreciation and amortization not normalized	26,373	8,032	123,435
ITC amortization	(2,115)	(2,262)	(77,919)
State taxes, net of federal benefit	14,692	21,386	10,241
Other, net	(9,325)	(8,640)	10,247
Total	154,379	155,561	220,791
Less amount classified as extraordinary item	–	(1,121)	(9,458)
Total Before Extraordinary Item	$154,379	$156,682	$230,249

In 1999 depreciation not normalized and ITC amortization included the result of the sale of coal-fired generation assets and the writeoff of NMP2. (See Note 8. Sale of Coal-Fired Generation Assets and Note 9. Jointly-Owned Generation Assets.)

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

December 31 (Thousands)	2001	2000
Current Deferred Tax Assets	$4,170	$5,007
Noncurrent Deferred Tax Liabilities		
Depreciation	$573,071	$546,372
Unfunded future income taxes	80,125	75,473
Accumulated deferred ITC	29,370	30,972
Deferred gain on generation plant sale	(109,246)	(94,181)
Pension benefits	102,109	67,064
Statement 106 postretirement benefits	(64,013)	(58,240)
Other	7,380	56,929
Total Noncurrent Deferred Tax Liabilities	618,796	624,389
Less amounts classified as regulatory liabilities		
Deferred income taxes	157,196	166,894
Noncurrent Deferred Income Taxes	$461,600	$457,495

Note 4 Long-term Debt

At December 31, 2001 and 2000, the company's consolidated long-term debt was:

	Maturity Dates	Interest Rates	Amount 2001	2000
(Thousands)				
First mortgage bonds [1]	2002 to 2023	6 3/4% to 10.06%	**$609,840**	$612,340
Pollution control notes – fixed	2006 to 2034	5 3/8% to 6.15%	**325,500**	306,000
Pollution control notes – variable	2015 to 2029	1.75% to 4.26%	**307,000**	326,500
Various long-term debt	2002 to 2030	4.2% to 10.48%	**1,137,809**	809,523
Putable asset term securities [2]	2033	7.75%	**300,000**	300,000
Obligations under capital leases			**36,960**	39,501
Unamortized premium and discount on debt, net			**(20,153)**	(21,765)
			2,696,956	2,372,099
Less debt due within one year – included in current liabilities			**225,678**	25,285
Total			**$2,471,278**	$2,346,814

At December 31, 2001, long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years are:

2002	2003	2004	2005	2006
$225,678	$80,613	$27,646	$55,378	$325,716

(1) Substantially all of the company's utility plant is subject to liens or mortgages securing its subsidiaries' first mortgage bonds. The after-tax extraordinary losses on early extinguishment of debt were $2 million or one cent per share in 2000 and $18 million or 15 cents per share in 1999.

(2) 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.

Note 5 Bank Loans and Other Borrowings

The company and its subsidiaries have credit agreements with various expiration dates in 2002 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, 2001, and $724 million at December 31, 2000.

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 $173 million of such short-term debt outstanding at December 31, 2001, and $419 million outstanding at December 31, 2000. The weighted-average interest rate on short-term debt was 2.6% at December 31, 2001, and 7.7% at December 31, 2000.

Note 6 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 100%-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.

PREFERRED STOCK REDEEMABLE SOLELY AT THE OPTION OF SUBSIDIARIES | At December 31, 2001 and 2000, the consolidated preferred stock redeemable solely at the option of subsidiaries was:

Series	Par Value Per Share	Redemption Price Per Share	Shares Authorized and Outstanding(1)	Amount 2001	Amount 2000
(Thousands)					
3.50%	$100	$101.00	220,000	**$22,000**	$22,000
3.75%	100	104.00	78,379	**7,838**	7,838
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
4.60%	100	101.00	30,000	**3,000**	3,000
4.75%	100	101.00	50,000	**5,000**	5,000
4.80%	100	100.00	2,589	**259**	300
5.25%	100	102.00	50,000	**5,000**	5,000
6.00%	100	–	5,180	**518**	518
6.00%	100	110.00	4,129	**413**	459
8.00%	3.125	–	108,843	**340**	381
Preferred stock issuance costs				**(3,316)**	(3,493)
Total				**$43,373**	$43,324

(1) At December 31, 2001, the company and its subsidiaries had 14,510,786 shares of $100 par value preferred stock, 12,800,000 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 1,000,000 shares of $1 par value preference stock authorized but unissued.

The company's subsidiaries redeemed or purchased the following amounts of preferred stock during the period 1999 through 2001:

Subsidiary Company	Date	Series	Amount
NYSEG:	February 1, 1999	7.40%	$25 million*
	April 1, 1999	3.75%	$7.2 million**
	April 1, 1999	4 1/2% (1949)	$2.8 million**
	April 1, 1999	4.15%	$1.4 million**
	April 1, 1999	4.40%	$4.8 million**
	April 1, 1999	4.15% (1954)	$3.1 million**
	December 10, 1999	6.30%	$25 million*
CMP	October 1, 2000	7.999%	$9.9 million*
CNG:	September 26, 2000	8.00%	$3,250*
	Various 2001	6.00%	$45,900*
	Various 2001	8.00%	$41,222***
Berkshire	September 30, 2001	4.80%	$41,000*

*Redeemed **Purchased at a discount ***Substantially all purchased at a premium

Note 7 Commitments

CAPITAL SPENDING | The company has commitments in connection with its capital spending program. Capital spending, excluding the RGS merger transaction, is projected to be $223 million in 2002 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 and compliance with environmental requirements.

NONUTILITY GENERATOR POWER PURCHASE CONTRACTS | NYSEG and CMP together expensed approximately $593 million for NUG power in 2001 and $439 million in 2000 (CMP beginning on September 1, 2000, the date it was acquired). NYSEG expensed $354 million in 1999 for NUG power. NYSEG and CMP estimate that together their NUG power purchases will total $637 million in 2002, $651 million in 2003, $672 million in 2004, $677 million in 2005 and $623 million in 2006.

Note 8 Sale of Coal-Fired Generation Assets

The company completed the sale of its Homer City generation assets to Edison Mission Energy in March 1999, and the sale of its remaining coal-fired generation assets to The AES Corporation in May 1999 for a total of $1.85 billion. The proceeds from the sale of those assets – net of taxes and transaction costs – in excess of the net book value of the generation assets, less funded deferred taxes, were used to write down NYSEG's 18% investment in NMP2 by $380 million. This treatment is in accordance with NYSEG's restructuring plan approved by the NYPSC in January 1998. NYSEG wrote down its investment by an additional $106 million due to the required writeoff of funded deferred taxes related to NMP2. These writedowns are reflected in depreciation and amortization on the 1999 consolidated statement of income. (See Note 9. Jointly-Owned Generation Assets.)

Note 9 Jointly-Owned Generation Assets

NYSEG | NYSEG had an 18% interest in the output and costs of NMP2 before it was sold. NYSEG's 18% share of NMP2's operating expenses until it was sold is included in various categories on the consolidated statements of income.

Sale of Nine Mile Point 2: On November 7, 2001, after receiving all regulatory approvals, NYSEG sold its 18% interest in NMP2 to Constellation Nuclear. For its share of NMP2, NYSEG received at closing $59 million in cash and a $59 million 11% promissory note, which will be paid in five annual payments unless it is prepaid.

On September 28, 2001, NYSEG and the Staff of the NYPSC reached agreement on a joint settlement with respect to the regulatory and ratemaking aspects of the sale of NYSEG's interest in NMP2. On October 26, 2001, the NYPSC issued an order approving the sale, which provided for an asset sale gain account of approximately $110 million to be established at the time of closing. Disposition of the asset sale gain is addressed under the settlement the company reached on January 15, 2002, with the NYPSC Staff and other parties on a joint proposal for a new five-year NYSEG electric rate plan and approval of the company's merger with RGS Energy.

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

In 1999 the majority of NYSEG's investment in NMP2 was recovered through a gain on the sale of the company's coal-fired generation assets. The remaining balance was written off pursuant to Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.

CMP | CMP has ownership interests in four 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, a 6% interest in Connecticut Yankee Atomic Power Company and a 4% interest in Vermont Yankee Nuclear Power Corporation. Maine Yankee, Yankee Atomic and Connecticut Yankee have been permanently shut down. Yankee Atomic has been decommissioned and Maine Yankee and Connecticut Yankee are in the process of being decommissioned. Vermont Yankee is an operating unit.

On March 31, 2001, CMP sold its 2.5% ownership interest in the Millstone Unit No. 3 nuclear unit. The net proceeds from the sale, $1.4 million including unfunded deferred taxes, were used to reduce a regulatory asset related to CMP's nonnuclear generating assets that were sold in April 1999. CMP contributed $1.3 million to the qualified nuclear trust fund, as part of the sale agreement, and is released from any liability for decommissioning the plant in the future.

On August 15, 2001, Vermont Yankee Nuclear Power Corporation reached an agreement to sell the Vermont Yankee nuclear power plant to Entergy Corporation. CMP has a 4% ownership interest in Vermont Yankee. The transaction includes 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. The sale is subject to the approval of the Public Service Board of Vermont, the NRC, the FERC and other regulatory authorities.

NUCLEAR INSURANCE | The Price-Anderson Act is a federal statute providing, among other things, a limit on the maximum liability for damages resulting from a nuclear incident. The public liability limit for a nuclear incident is approximately $8.9 billion. Should losses stemming from a nuclear incident exceed the commercially available public liability insurance, each licensee of a nuclear facility would be liable for up to $84 million per incident, payable at a rate not to exceed $10 million per year. The $84 million assessment is subject to periodic inflation indexing and a 5% surcharge should funds prove insufficient to pay claims associated with a nuclear incident.

CMP's maximum liability for its interest in Vermont Yankee would be approximately $4 million per incident. The Price-Anderson Act also requires indemnification for precautionary evacuations whether or not a nuclear incident actually occurs.

In addition to the insurance required by the Price-Anderson Act, the nuclear generating facilities carry additional nuclear property damage insurance. Property insurance is obtained through the Nuclear Insurance Pools and Nuclear Electric Insurance Limited and other commercial sources.

NUCLEAR PLANT DECOMMISSIONING COSTS | CMP's estimated liability for decommissioning its various interests in the jointly-owned nuclear plants is $202 million in 2002 dollars. Its current share of these costs is recovered through electric rates.

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.

Note 18 **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 17 waste sites. The 17 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 17 sites, seven sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, five are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and six 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 13 of the 17 sites. 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 52 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, 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 52 sites.

The company's estimate for all costs related to investigation and remediation of its 52 sites ranges from $101 million to $212 million at December 31, 2001. 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 $101 million at December 31, 2001, and $88 million at December 31, 2000. The company recorded a corresponding regulatory asset, net of insurance recoveries, since it expects to recover the net costs in rates.

Note 12 Fair Value of Financial Instruments

The carrying amounts and estimated fair values of some 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	**2001**	**2001**	2000	2000
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
Investments – classified as available-for-sale	**$38,508**	**$38,550**	$77,128	$77,279
First mortgage bonds	**$606,112**	**$623,055**	$608,134	$618,248
Pollution control notes – fixed	**$325,500**	**$333,056**	$306,000	$313,780
Pollution control notes – variable	**$307,000**	**$307,000**	$326,500	$326,500
Various long-term debt	**$1,123,557**	**$1,124,911**	$795,296	$836,201
Putable asset term securities	**$297,827**	**$310,017**	$296,668	$327,058

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. The carrying amount approximates fair value because the special deposits have been invested in securities that mature within one year.

The company has been evaluating the carrying value of CMP Group's investment in NEON Communications, Inc. because there has been a significant decline in the market value of NEON common shares over the past 18 months. That decline is consistent with the market performance of telecommunications businesses as a whole. During the third quarter of 2001, the company determined that the decline in NEON's market value was other than temporary and wrote down the cost basis of the investment in NEON to $12 million, based on the closing market price of NEON common shares at the end of September 2001. The writedown totaled $46 million after taxes, or 39 cents per share. The company's investment in NEON is classified as available-for-sale, accounted for by the cost method and carried at its fair value, with any changes recognized in other comprehensive income. The fair value of the investment in NEON was $12 million at December 31, 2001, but it dropped significantly in January 2002 due to a further decline in the market value of NEON's common shares.

Note 12 Accumulated Other Comprehensive Income

(Thousands)	Balance January 1 1999	1999 Change	Balance December 31 1999	2000 Change	Balance December 31 2000	2001 Change	Balance December 31 2001
Foreign currency translation adjustment, net of income tax benefit of $– for 1999, 2000 and 2001	–	$(93)	$(93)	$7	$(86)	$86	–
Unrealized gains (losses) on investments:							
Unrealized holding (losses) during period, net of income tax benefit of $– for 1999, $23,804 for 2000 and $7,980 for 2001	–	(1,588)	(1,588)	(32,519)	(34,107)	(10,400)	$(44,507)
Reclassification adjustment for losses included in net income, net of income tax benefit of $32,674 for 2001	–	–	–	–	–	45,748	45,748
Net unrealized gains (losses) on investments	–	(1,588)	(1,588)	(32,519)	(34,107)	35,348	1,241
Minimum pension liability adjustment, net of income tax benefit of $339 for 2000 and $1,828 for 2001	–	–	–	(630)	(630)	(2,546)	(3,176)
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
Unrealized losses during period on derivatives qualified as hedges, net of income tax benefit of $59,510 for 2001	–	–	–	–	–	(89,955)	(89,955)
Reclassification adjustment for losses included in net income, net of income tax benefit of $7,416 for 2001	–	–	–	–	–	11,305	11,305
Net unrealized (losses) on derivatives qualified as hedges	–	–	–	–	–	(20,400)	(20,400)
Accumulated Other Comprehensive Income (Loss)	–	$(1,681)	$(1,681)	$(33,142)	$(34,823)	$12,488	$(22,335)

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 2001, 2000 and 1999 had it been determined consistent with Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation.

The company may grant options and stock appreciation rights (SARs) to senior management and certain other key employees under its stock option plan. Options granted in 1999 vest over either two-year or three-year periods, and options granted in 2000 and 2001 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, 2001 and 2000, unoptioned shares totaled 4.5 million at December 31, 2001, and 6.2 million at December 31, 2000.

The company recorded compensation expense (benefit) for options/SARs of less than $(1) million in 2001, $(1) million in 2000 and $(5) million in 1999.

During 2001 1,799,000 options/SARs were granted with a weighted-average exercise price 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 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.

During 1999 1,122,412 options/SARs were granted with a weighted-average exercise price of $26.68. 3,118 options with a weighted-average exercise price of $16.90 and 102,362 SARs with a weighted-average exercise price of $18.70 were exercised in 1999. 30,000 options/SARs with an exercise price of $18.43 were forfeited in 1999. The 2,277,858 options/SARs outstanding at December 31, 1999, had a weighted-average exercise price of $21.75. Of those outstanding at December 31, 1999, 206,170 options/SARs with exercise prices ranging from $10.88 to $14.69 and a weighted-average remaining life of seven years had a weighted-average exercise price of $10.88 and 2,071,688 options/SARs with exercise prices ranging from $17.94 to $28.72 and a weighted-average remaining life of nine years had a weighted-average exercise price of $22.83. Of those exercisable at December 31, 1999, 206,170 options/SARs with exercise prices ranging from $10.88 to $14.69 had a weighted-average price of $10.88 and 645,172 options/SARs with exercise prices ranging from $17.94 to $28.72 had a weighted-average exercise price of $22.97.

The company's Long-term Executive Incentive Share Plan provides participants cash awards if certain shareholder return criteria are achieved. There were 95,418 performance shares outstanding at December 31, 2001, and 140,782 performance shares outstanding at December 31, 2000. There was no compensation expense for 2001 and compensation expense was $1 million for 2000 and 1999. Beginning January 1, 2001, no new performance shares are granted under this plan (other than dividend performance shares), which will be eliminated in 2003.

Note 14 Retirement Benefits

	Pension Benefits		Postretirement Benefits	
	2001	2000	**2001**	2000
(Thousands)				
Change in projected benefit obligation				
Benefit obligation at January 1	**$1,242,769**	$773,086	**$395,857**	$256,983
Service cost	**23,967**	20,979	**5,091**	7,031
Interest cost	**90,949**	70,486	**25,024**	24,213
Plan participants' contributions	**-**	-	**255**	-
Plan amendments	**39,614**	7,364	**(26,967)**	(40,152)
Actuarial loss	**37,949**	66,518	**31,895**	23,614
Business combination	**-**	354,510	**-**	138,353
Curtailment	**(670)**	-	**(394)**	-
Special termination benefits	**2,551**	-	**-**	-
Benefits paid	**(67,681)**	(50,174)	**(22,334)**	(14,185)
Projected benefit obligation at December 31	**$1,369,448**	$1,242,769	**$408,427**	$395,857
Change in plan assets				
Fair value of plan assets at January 1	**$1,925,905**	$1,387,690	**$40,226**	-
Actual return on plan assets	**(37,564)**	137,402	**(1,804)**	$(1,571)
Employer contributions	**433**	-	**22,291**	12,323
Plan participants' contributions	**-**	-	**255**	-
Business combination	**-**	451,865	**-**	43,717
Actual expense paid	**-**	(878)	**-**	(58)
Adjustment	**959**	-	**-**	-
Benefits paid	**(67,681)**	(50,174)	**(22,334)**	(14,185)
Fair value of plan assets at December 31	**$1,822,052**	$1,925,905	**$38,634**	$40,226
Funded status	**$452,604**	$683,136	**$(369,793)**	$(355,631)
Unrecognized net actuarial (gain) loss	**(59,273)**	(337,464)	**46,983**	6,409
Unrecognized prior service cost	**58,277**	27,311	**(60,365)**	(40,152)
Unrecognized net transition (asset) obligation	**(15,707)**	(22,945)	**100,384**	109,510
Prepaid (accrued) benefit cost	**$435,901**	$350,038	**$(282,791)**	$(279,864)

Other comprehensive income decreased $3 million in 2001 as a result of a change in additional minimum pension liability.

CNE's, CMP Group's and CTG Resources' postretirement benefits were partially funded as of December 31, 2001 and 2000.

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

The company assumed a 12% annual rate of increase in the costs of covered health care benefits for 2001 that gradually decreases to 5% by the year 2005.

	Pension Benefits			Postretirement Benefits		
	2001	2000	1999	**2001**	2000	1999
(Thousands)						
Components of net periodic benefit cost						
Service cost	**$23,967**	$20,979	$19,083	**$5,091**	$7,031	$6,291
Interest cost	**90,949**	70,486	52,325	**25,024**	24,213	17,132
Expected return on plan assets	**(161,731)**	(123,772)	(100,195)	**(3,378)**	(1,559)	–
Amortization of prior service cost	**7,822**	1,706	1,833	**(6,753)**	–	–
Recognized net actuarial gain	**(41,750)**	(40,103)	(37,442)	**(4,122)**	(2,630)	(3,771)
Amortization of transition (asset) obligation	**(7,238)**	(7,238)	(7,238)	**9,126**	9,126	9,527
Deferral for future recovery	**–**	–	–	**–**	(5,395)	(4,377)
Special termination benefit charge	**2,551**	–	–	**–**	–	–
Curtailment charge (credit)	**–**	–	(16,773)	**–**	–	15,402
Settlement charge (credit)	**–**	–	–	**–**	–	(11,023)
Net periodic benefit cost	**$(85,430)**	$(77,942)	$(88,407)	**$24,988**	$30,786	$29,181

The sale of the company's coal-fired generation assets in 1999 resulted in a curtailment gain and a settlement gain, which were the result of the termination of certain generation employees. The curtailment gain reduced the expected years of future service under the pension benefit plan and the settlement gain reduced the postretirement benefit obligation.

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 $68 million as of December 31, 2001, and $75 million as of December 31, 2000. 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	$30 million	$(26 million)

Note [illegible] 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
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)**(1)	**$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)(2)	$513,921
Interest Charges, Net	$105,826	$41,229	$5,448	$152,503
Income Taxes	$147,454	$12,378	$(3,150)	$156,682
Income Before Extraordinary Item	$230,328	$15,920	$(9,569)(2)	$236,679
Extraordinary Loss, Net of Tax	$1,357	$288	–	$1,645
Net Income	$228,971	$15,632	$(9,569)(2)	$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
1999				
Operating Revenues	$1,889,318	$331,745	$57,545	$2,278,608
Depreciation and Amortization	$627,829	$17,674	$3,467	$648,970
Operating Income	$515,644	$62,194	$(15,255)	$562,583
Interest Charges, Net	$111,032	$17,579	$4,297	$132,908
Income Taxes	$209,639	$16,140	$4,470	$230,249
Income Before Extraordinary Item	$200,725	$27,833	$7,759	$236,317
Extraordinary Loss, Net of Tax	$15,124	$2,442	–	$17,566
Net Income	$185,601	$25,391	$7,759	$218,751
Total Assets	$2,306,572	$645,261	$821,338	$3,773,171
Capital Spending	$44,943	$28,682	$9,049	$82,674

(1) Includes the effect of the writedown of CMP Group's investment in NEON Communications, Inc. that decreased net income by $46 million.

(2) Includes the effect of a nonrecurring loss from the sale of XENERGY, Inc. that decreased net income by $4 million.

Note 16 Quarterly Financial Information (Unaudited)

Quarter Ended (Thousands, except per share amounts)	March 31	June 30	September 30	December 31
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)**[2]	**$66,489**
Earnings (Loss) Per Share, basic and diluted	**$.98**	**$.23**	**$(.18)**[2]	**$.57**
Dividends Per Share	**$.23**	**$.23**	**$.23**	**$.23**
Average Common Shares Outstanding	**117,386**	**116,399**	**116,436**	**116,623**
Common Stock Price[1]				
High	**$20.31**	**$21.20**	**$22.14**	**$21.49**
Low	**$16.96**	**$17.41**	**$18.99**	**$17.65**
2000				
Operating Revenues	$684,426	$571,919	$651,146	$1,052,029
Operating Income	$169,326	$98,116	$101,282	$145,197
Income Before Extraordinary Item	$93,327	$56,471	$33,349	$53,532
Extraordinary Loss, Net of Tax	–	–	–	$1,645
Net Income	$93,327	$56,471[3]	$33,349[4]	$51,887
Earnings Per Share, basic and diluted	$.83	$.50[3]	$.30[4]	$.44
Dividends Per Share	$.22	$.22	$.22	$.22
Average Common Shares Outstanding	112,777	113,397	112,812	117,950
Common Stock Price[1]				
High	$23.63	$22.94	$23.50	$22.63
Low	$18.81	$19.00	$17.94	$18.44

(1) The company's common stock is listed on the New York Stock Exchange. The number of shareholders of record was 34,354 at December 31, 2001.

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

(3) Includes the effect of the nonrecurring benefit from the sale of generation assets that increased net income by $8 million and earnings per share by 7 cents.

(4) Includes the effect of a nonrecurring loss from the sale of XENERGY, Inc. that decreased net income by $4 million and earnings per share by 4 cents.

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, 2001, 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, 2001, 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

Robert E. Rude
Vice President and Controller

Wes Von Schack

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

PRICEWATERHOUSECOOPERS

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

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 ("the Company") and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Notes 1 and 12 to the consolidated financial statements, 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).

PricewaterhouseCoopers LLP

New York, New York
January 25, 2002

Selected Financial Data

(Thousands, except per share amounts)	2001	2000[2]	1999	1998	1997	1996
Operating Revenues						
Sales and services	**$3,759,787**	$2,959,520	$2,278,608	$2,499,568	$2,170,102	$2,108,865
Operating Expenses						
Electricity purchased and fuel used in generation	**1,334,507**	1,073,728	905,367	992,236	643,063	582,855
Natural gas purchased	**694,038**	496,509	186,722	158,757	164,661	180,866
Other operating expenses	**570,186**	435,965	312,129	367,897	406,830	412,915
Maintenance	**139,395**	108,106	85,849	111,503	110,373	107,697
Depreciation and amortization	**204,281**	165,524	648,970[4]	191,462	202,151	192,884
Other taxes	**192,772**	165,767	179,028	204,483	205,974	206,229
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	**3,122,899**	2,445,599	1,716,025	2,026,338	1,733,052	1,683,446
Operating Income	**636,888**	513,921	562,583	473,230	437,050	425,419
Writedown of Investment	**78,422[1]**	–	–	–	–	–
Other (Income) and Deductions	**(15,003)**	(32,906)	(39,597)	7,474	11,113	16,020
Interest Charges, Net	**217,028**	152,503	132,908	125,557	123,199	122,729
Preferred Stock Dividends of Subsidiaries	**14,455**	963	2,706	8,583	9,342	9,530
Income Before Income Taxes	**341,986**	393,361	466,566	331,616	293,396	277,140
Income Taxes	**154,379**	156,682	230,249	137,411	118,185	108,429
Income Before Extraordinary Item	**187,607**	236,679	236,317	194,205	175,211	168,711
Extraordinary Loss on Early Extinguishment of Debt, Net of Income Tax Benefit of $1,121 for 2000 and $9,458 for 1999	**–**	1,645	17,566	–	–	–
Net Income	**187,607[1]**	235,034[3]	218,751[5]	194,205	175,211[6]	168,711[7]
Common Stock Dividends	**107,342**	99,606	98,725	100,487	95,496	99,611
Retained Earnings Increase	**$80,265**	$135,428	$120,026	$93,718	$79,715	$64,717
Average Common Shares Outstanding	**116,708**	114,213	116,316	128,742	136,306	142,255
Earnings Per Share, basic and diluted	**$1.61[1]**	$2.06[3]	$1.88[5]	$1.51	$1.29[6]	$1.19[7]
Dividends Paid Per Share	**$.92**	$.88	$.84	$.78	$.70	$.70
Book Value Per Share of Common Stock at Year End	**$15.26**	$14.59	$12.84	$13.61	$13.36	$12.70
Capital Spending	**$222,875**	$168,320	$82,674	$137,350	$129,551	$215,731
Total Assets	**$7,269,232**	$7,013,728	$3,773,171	$4,902,085	$5,044,914	$5,064,816
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	**$2,816,278**	$2,346,814	$1,235,089	$1,460,120	$1,475,224	$1,505,814

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 2001 presentation.

(1) Includes the $78 million writedown of CMP Group's investment in NEON Communications, Inc. that decreased net income by $46 million and earnings per share by 39 cents.

(2) 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.

(3) Includes the effects of the nonrecurring benefit from the sale of the company's coal-fired generation assets that increased net income by $8 million and earnings per share by 7 cents and the nonrecurring loss from the sale of XENERGY, Inc. that decreased net income by $4 million and earnings per share by 4 cents.

(4) Depreciation and amortization includes accelerated amortization of NMP2 related to the sale of the company's coal-fired generation assets, authorized by the NYPSC. (See Note 8. Sale of Coal-Fired Generation Assets.)

(5) Includes the effect of the extraordinary loss from the early retirement of debt that decreased net income by $18 million and earnings per share by 15 cents and the nonrecurring benefit from the sale of the company's coal-fired generation assets net of the writeoff of NMP2 that increased net income by $14 million and earnings per share by 12 cents.

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

(7) Includes the effect of the writedown of the investment in EnerSoft Corporation that decreased net income by $10 million and earnings per share by 7 cents.

(Thousands)	2001	2000	1999	1998	1997	1996
Electric Deliveries						
(Megawatt-hours)						
Residential	**8,594**	6,473	5,447	5,199	5,267	5,393
Commercial	**6,527**	4,504	3,517	3,428	3,495	3,430
Industrial	**6,525**	4,613	3,383	3,222	3,065	2,992
Other	**1,592**	1,543	1,496	1,428	1,411	1,401
Total Retail	**23,238**	17,133	13,843	13,277	13,238	13,216
Wholesale	**6,048**	6,214	10,978	22,711	10,406	7,914
Total Electric Deliveries	**29,286**	23,347	24,821	35,988	23,644	21,130
Electric Revenues						
Residential	**$998,846**	$820,093	$747,964	$720,546	$728,777	$744,439
Commercial	**622,996**	460,453	393,623	393,857	403,481	400,841
Industrial	**314,527**	263,633	237,637	246,589	243,868	242,792
Other	**162,987**	153,283	159,730	158,215	157,517	158,377
Total Retail	**2,099,356**	1,697,462	1,538,954	1,519,207	1,533,643	1,546,449
Wholesale	**238,094**	212,630	312,727	611,852	232,138	162,232
Other	**167,446**	113,518	37,637	28,810	26,383	14,466
Total Electric Revenues	**$2,504,896**	$2,023,610	$1,889,318	$2,159,869	$1,792,164	$1,723,147
Natural Gas Deliveries						
(Dekatherms)						
Residential	**52,846**	42,238	23,327	20,960	24,357	25,470
Commercial	**20,699**	15,823	8,247	7,909	10,178	10,146
Industrial	**2,847**	2,690	1,669	1,779	2,409	2,726
Other	**12,726**	10,074	2,677	2,568	2,735	2,230
Transportation of customer-owned natural gas	**58,882**	37,314	23,426	20,962	19,645	20,970
Total Retail	**148,000**	108,139	59,346	54,178	59,324	61,542
Wholesale	**9,298**	10,674	8,617	7,527	3,027	4,056
Total Natural Gas Deliveries	**157,298**	118,813	67,963	61,705	62,351	65,598
Natural Gas Revenues						
Residential	**$576,115**	$390,794	$181,579	$171,437	$190,564	$198,338
Commercial	**226,215**	145,318	63,112	61,059	83,091	83,393
Industrial	**26,220**	19,339	8,123	8,155	13,044	14,509
Other	**89,524**	68,652	14,745	14,257	17,839	15,697
Transportation of customer-owned natural gas	**73,213**	59,901	33,572	29,589	21,949	17,476
Total Retail	**991,287**	684,004	301,131	284,497	326,487	329,413
Wholesale	**37,748**	55,184	21,831	17,791	9,114	10,444
Other	**(2,911)**	32,943	8,783	3,743	2,224	4,528
Total Natural Gas Revenues	**$1,026,124**	$772,131	$331,745	$306,031	$337,825	$344,385

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.

Alison P. Casarett, a director since 1979, is Dean Emeritus at Cornell University in Ithaca, New York and Emeritus Professor of Radiation Biology at the New York State College of Veterinary Medicine of Cornell University.

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.

Paul L. Gioia, a director since 1991, is of counsel at LeBoeuf, Lamb, Greene & MacRae, attorneys-at-law in Albany, 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 of 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, DeFleur, Gioia, Jagger

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

Executive Compensation and Succession: Castiglia, Aurelio, Lynch

Nominating: 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

Robert E. Rude
Vice President and Controller

Angela M. Sparks-Beddoe
Vice President – Governmental Affairs

Ralph R. Tedesco
President – NYSEG

Denis E. Wickham
Senior Vice President – Transmission and Supply

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

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

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.

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

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

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

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

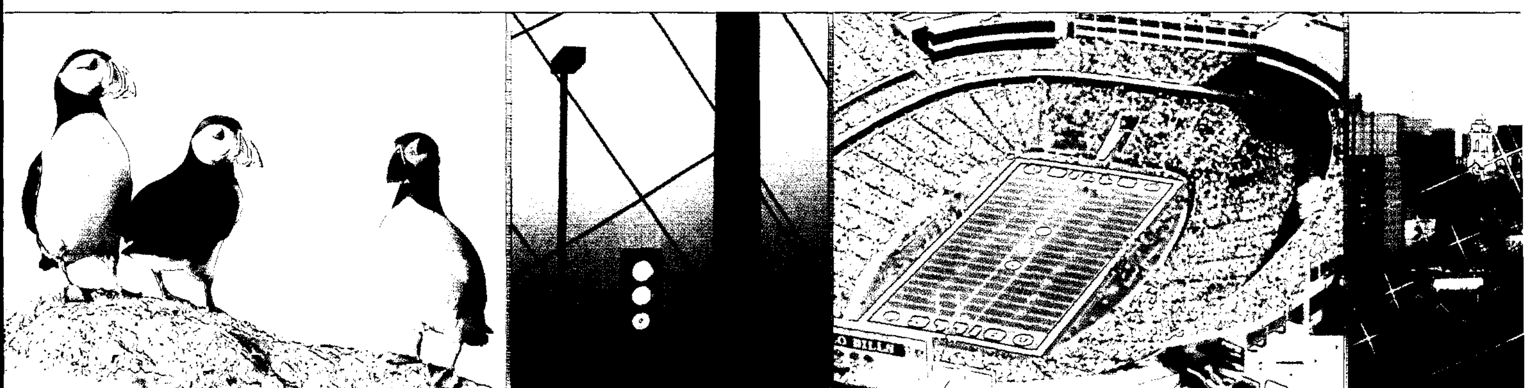
Connecticut Natural Gas Corporation (CNG)
10 State House Square, 6th Floor | P.O. Box 1500 | Hartford, CT 06144-1500
www.cngcorp.com

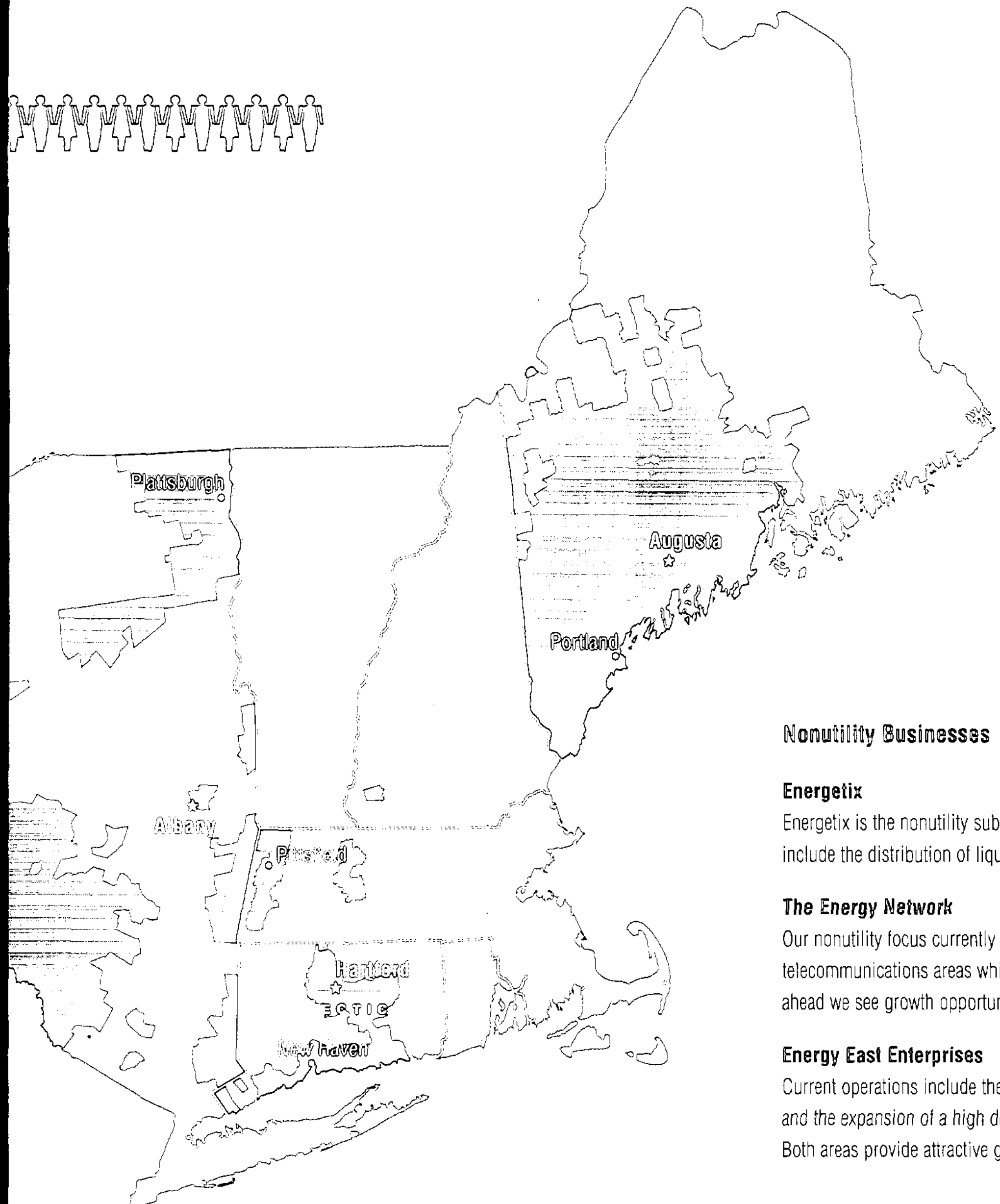
The Berkshire Gas Company (Berkshire)
115 Cheshire Road | Pittsfield, MA 01201
www.berkshiregas.com

The Energy Network, Inc.
81 State Street | Stephens Square, 5th Floor | Binghamton, NY 13901

Energy East Enterprises, Inc.
81 State Street | Stephens Square, 5th Floor | Binghamton, NY 13901

Energy East is a respected super regional energy services and delivery company that our customers can depend upon every day. We are a motivated and skilled team of professionals dedicated to creating shareholder value through our focus on profitable growth, operational excellence and strong customer partnerships.





Nonutility Businesses

Energetix

Energetix is the nonutility subsidiary of RGS Energy Group. 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, energy services and telecommunications areas which complement our core utility business. Looking ahead we see growth opportunities in peaking generation.

Energy East Enterprises

Current operations include the development of a gas distribution business in Maine and the expansion of a high deliverability gas storage facility in upstate New York. Both areas provide attractive growth opportunities.

Fourth of July fireworks – Portland, Maine

CMP

555,000	Electricity customers
12,616	Electricity delivered (gwh)
815	Electricity revenue ($ million)
1,866	Assets ($ million)

Connecticut River Museum – Essex, Connecticut

SCG

169,000	Natural gas customers
29,884	Natural gas delivered (000 dth)
294	Natural gas revenue ($ million)
865	Assets ($ million)

Old State Capital – Hartford, Connecticut

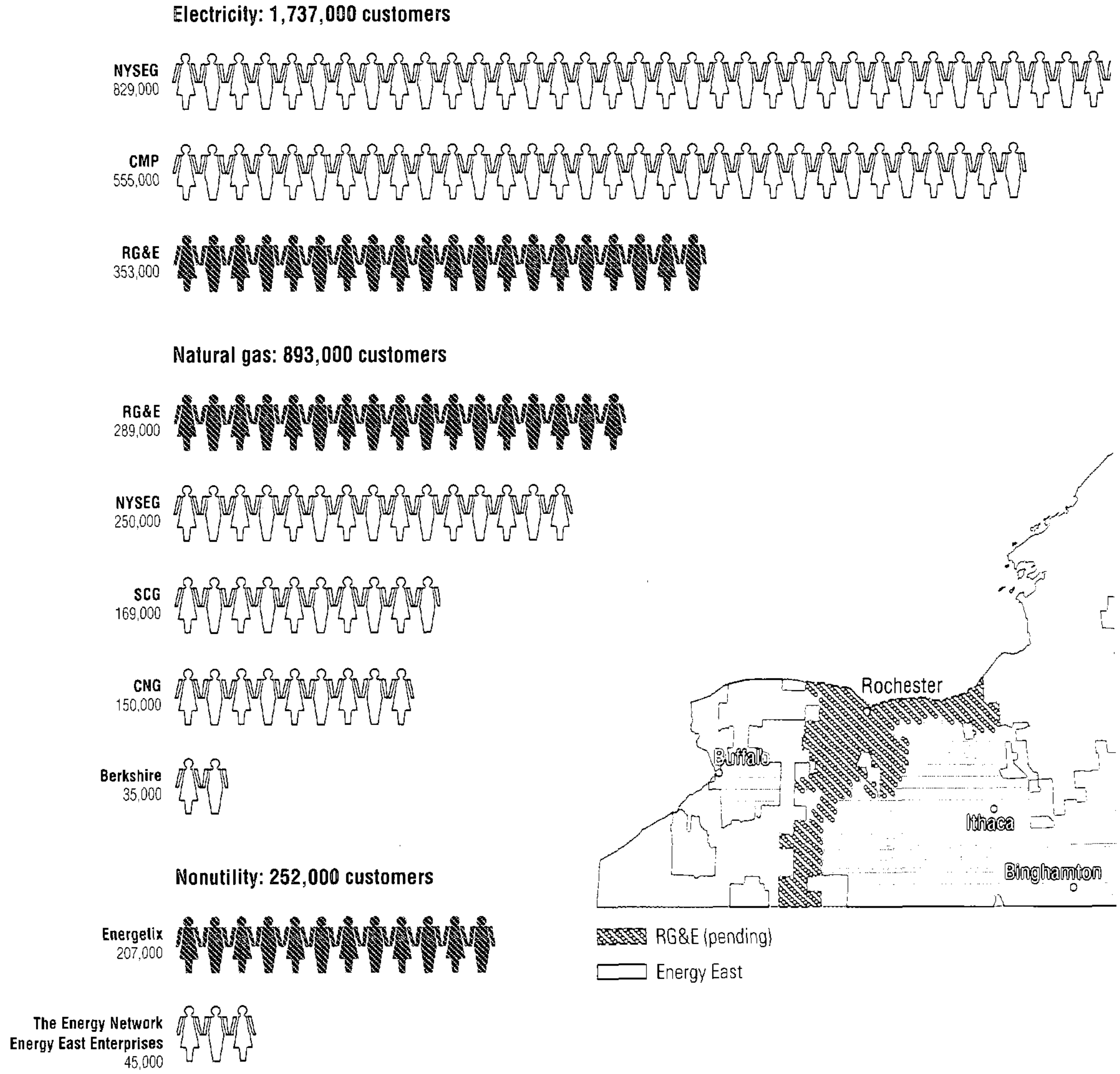
CNG

150,000	Natural gas customers
37,379	Natural gas delivered (000 dth)
321	Natural gas revenue ($ million)
683	Assets ($ million)

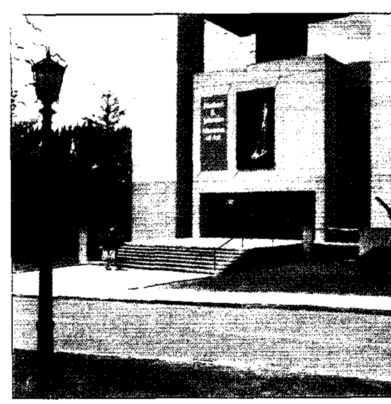
Rockwell Museum – Stockbridge, Massachusetts

Berkshire

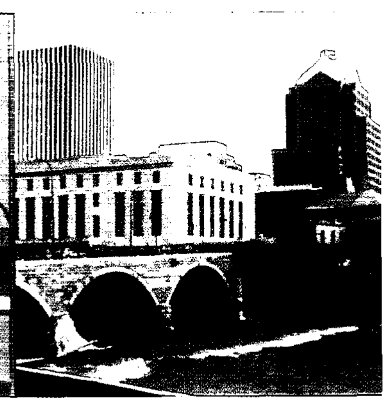
35,000	Natural gas customers
7,659	Natural gas delivered (000 dth)
59	Natural gas revenue ($ million)
189	Assets ($ million)



The year 2001 was highlighted by the announcement of a strategic combination with RGS Energy Group. This merger, combined with the four mergers completed in 2000 with Connecticut Energy Corporation, CMP Group, CTG Resources and Berkshire Energy, will make Energy East one of the largest, most diversified energy providers in the Northeast, servicing half of upstate New York and nearly 3 million customers. Energy East's customer base, with the pending RGS Energy combination, will have almost tripled in three years, providing us with new opportunities for growth and profitability.



Herbert F. Johnson Museum of Art, Cornell University – Ithaca, New York



Genesee River – Rochester, New York

NYSEG

829,000	Electricity customers
250,000	Natural gas customers
16,669	Electricity delivered (gwh)
62,637	Natural gas delivered (000 dth)
1,690	Electricity revenue ($ million)
348	Natural gas revenue ($ million)
3,014	Assets ($ million)

RG&E

353,000	Electricity customers
289,000	Natural gas customers
9,249	Electricity delivered (gwh)
49,903	Natural gas delivered (000 dth)
728	Electricity revenue ($ million)
311	Natural gas revenue ($ million)
2,453	Assets ($ million)

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EnergyEast