Restoring Va

1998 ANNUA

Niagara Mohawk

Niagara Mohawk®

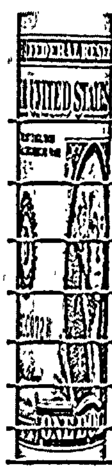
Key Information

Financial (in thousands of dollars)	1998	1997	% Change
Total operating revenues	$3,826,373	$3,966,404	(3.5)
Income available for common stockholders	($157,380)	$145,938	(207.8)
Earnings before interest, taxes, depreciation and amortization (EBITDA)	$990,532	$961,502	3.0
Total assets	$13,861,187	$9,584,141	44.6
Capital expenditures	$392,200	$290,757	34.9
Per Share			
Basic and diluted earnings	($0.95)	$1.01	(194.1)
Book value at year-end	$16.92	$18.89	(10.4)
Market price at year-end	$16 1/8	$10 1/2	53.6
Electric Sales (millions of KWh)			
Public electric sales	32,855	33,390	(1.6)
Total electric sales	36,432	37,136	(1.9)
Electric customers at end of year	1,555,000	1,558,000	(0.2)
Gas Sales (thousands of dekatherms)			
Natural gas sales	65,042	78,681	(17.3)
Natural gas transported	127,850	152,813	(16.3)
Gas customers at end of year	536,000	533,000	0.6

The 1998 Revenue Dollar

Residential Customers	41¢
Commercial Customers	35¢
Industrial Customers	14¢
Other	10¢

*... and Where it Went**



23¢	Independent Power Producers
14¢	Wages & Benefits
13¢	Income & Other Taxes
12¢	Depreciation & Amortization of MRA
11¢	Other
10¢	Fuel & Purchased Power
10¢	Interest
7¢	Gas Purchased

* Excludes the effect of the *PowerChoice* charge

To Our Shareholders

Thanks to your patience and support, and to the remarkable efforts of talented employees throughout our company, 1998 was a year of great achievement for Niagara Mohawk. Indeed, it was a year in which the company overcame wide-ranging challenges that included a record-breaking financing and devastating natural disasters.

Not long ago, Niagara Mohawk faced a problem that some considered unsolvable. The company was being crushed by government-mandated, above-market payments to independent power producers ("IPPs"). But in March 1998, we achieved regulatory approval of a Master Restructuring Agreement ("MRA") that substantially resolved our IPP payment problem. At the same time, we won approval of our *PowerChoice* plan for creating a competitive electricity market. In June, we successfully navigated the tumultuous financial markets and consummated the financing needed to close the MRA. Our $3.45-billion debt sale, at an average interest rate of about 7.4 percent, was the largest high-yield financing of the decade, and the second-largest high-yield offering in history. The MRA was the subject of an extensive profile in Institutional Investor Magazine and was named 'Breakthrough Energy Deal of the Year' by Investment Dealer's Digest.

Niagara Mohawk Holdings

With the approval of *PowerChoice* and the completion of the MRA, we began implementation of our strategy to become a regulated energy-delivery company while also pursuing unregulated opportunities to create shareholder value. After obtaining your approval at our annual meeting and required regulatory approvals, we created a new corporate structure. Niagara Mohawk Holdings, Inc. is now the parent company of Niagara Mohawk, a regulated electricity and natural gas distribution company, and Opinac NA, a wholly owned unregulated subsidiary. Your shares of Niagara Mohawk Power Corp. common stock were automatically exchanged for stock in Niagara Mohawk Holdings in March 1999, and continue to trade under the symbol "NMK." Darlene D. Kerr is the Chief Operating Officer of the regulated company, while Albert J. Budney, Jr. is the CEO and President of Opinac NA. This new structure gives your company the flexibility to compete more effectively in the new energy marketplace.

Sale of Generating Assets

As part of our *PowerChoice* plan, we have begun the process of divesting our non-nuclear generating assets. In December, we announced an agreement to sell our hydroelectric facilities to Orion Power Holdings for $425 million, and an agreement to sell our Huntley and Dunkirk coal-fired electric generating stations to NRG Energy for $355 million. These sales are expected to close in mid-1999 and are subject to customary conditions, including the receipt of all regulatory approvals. Proceeds from these sales will be used to accelerate the retirement of debt, consistent with our plan to create shareholder value. We are continuing efforts to sell our remaining fossil generation assets.

1998 Results

The year 1998 was marked by notable achievements that returned Niagara Mohawk to financial stability, but required significant non-cash charges to earnings. The company reported a 1998 loss of $157.4 million, or a loss of 95 cents per share, compared to 1997 earnings of $145.9 million, or $1.01 per share.

In a year of important achievements for the company, the most important was the closing of the MRA with IPPs in June. The MRA allowed the company to terminate, restate or amend contracts which represented about 75 percent of the company's over-market purchase power obligations. In return, the IPPs received approximately $3.9 billion in cash and 20.5 million shares of common stock. As part of its ***PowerChoice*** agreement, Niagara Mohawk will recover the cost of the MRA over 10 years. Accordingly, the company established a regulatory asset to reflect the cost of the MRA, and will amortize it as a non-cash charge to earnings over the 10-year recovery period.

continued

In approving *PowerChoice*, the New York Public Service Commission limited the value of the MRA regulatory asset, which resulted in a one-time non-cash charge to earnings of $263.2 million, or $1.03 per share, in 1998. Earnings in 1998 were also affected by the incremental costs of a January ice storm and a Labor Day windstorm, reducing earnings by approximately 24 cents per share and 6 cents per share, respectively. Additionally, results were negatively impacted by the regulatory treatment of the MRA regulatory asset and the dilution caused by the issuance of 42.9 million shares of common stock in connection with the MRA.

Although earnings were depressed as a result of the non-cash charges related to the MRA, payments to IPPs were reduced by $321.9 million in 1998, compared to 1997. However, these reductions were offset in part as fuel for electric generation increased $60.5 million, and interest charges, primarily related to the debt issued in connection with the MRA, increased $78.7 million.

More recently, in keeping with our overall strategy to focus on our core energy-delivery business, we announced our intent to pursue the sale of our nuclear assets. We believe Nine Mile Point Unit One and Unit Two will be attractive to a buyer interested in pursuing a nuclear strategy. In fact, our nuclear operations logged another successful year as Unit One finished 1998 with a 90 percent capacity factor and Unit Two, in a refueling year, achieved a capacity factor of 73 percent. In addition, there was a smooth transition in leadership of our nuclear operations as John H. Mueller succeeded the retiring B. Ralph Sylvia as Chief Nuclear Officer.

Our Accomplishments

Other notable achievements in operational areas reinforced our belief in our ability to excel in the energy delivery business. Performance in the area of customer service improved dramatically, as PSC-reported customer complaints dropped 40 percent to their lowest level in five years. In addition, our customer satisfaction index continued to improve, as we exceeded our goal for the second consecutive year. Again in 1998, we provided our customers with superior gas service at prices that were the lowest of any New York utility.

In September, also as part of *PowerChoice*, we implemented the first phase of a three-year electricity price reduction. This reduction, the first we have been able to implement in decades, is expected to help stimulate our service area economy and save or create more than 8,000 jobs.

All of these accomplishments would be notable in any year, but they are underscored by the reality that they were achieved in a year when the company faced two natural disasters that wrought destruction on a level never before seen in our service area.

In January, an ice storm of a magnitude that is expected to occur only once every 100 years devastated our electric transmission and distribution system in Northern New York State. Niagara Mohawk mobilized a response effort that reconstructed our electric system over difficult terrain, in bitter, mid-winter conditions. With the assistance of crews from 26 other companies working around the clock, and in cooperation with state, federal and local officials and human service agencies, we restored service completely in only three weeks, replacing more than 8,000 utility poles and 2 million feet of cable. The company's efforts were justly recognized as we were named one of the first recipients of the Edison Electric Institute's Emergency Response Award.

A second natural disaster struck with little warning later in the year. On Labor Day, a windstorm with hurricane-force winds ripped through Central New York. Once again, Niagara Mohawk's people met the challenge, restoring power in one week and earning widespread public praise. The company's reputation for emergency restoration was further recognized when Niagara Mohawk was one of three U.S. utilities asked to send crews to help restore power in Puerto Rico following the widespread destruction of Hurricane Georges. Some 150 company personnel rotated in and out of Puerto Rico over a seven-week period, successfully restoring service and winning the admiration of Puerto Rico's citizens.

Within Opinac NA, our utility investment in Canada remains profitable, our energy commodity brokering and energy services businesses are growing, and our fiber optic partner, Telergy, is expanding its operations.

Our accomplishments did not go unrecognized by the financial community. As the year progressed, Standard & Poor's and Moody's Investors Service both continued to raise their ratings on the company's securities, returning the rating on our first mortgage bonds to the investment-grade level for the first time since 1995. Niagara Mohawk's common stock also reflected the company's accomplishments in 1998, starting the year at $10-1/2, and closing at $16-1/8, up 54 percent for the year.

Looking Ahead

In the coming months, our strategy will be simple and straightforward: Hold down costs, pay down debt, and continuously improve service. We will carefully evaluate new business opportunities, but will be guided by the realization that in the short term, the greatest opportunity for building shareholder value lies in reducing our debt. Although earnings will continue to be depressed for several years, cash flow has improved markedly, giving the company the flexibility to reduce debt, improve operations and look for other ways to strengthen your investment in Niagara Mohawk.

In 1998, we added two outstanding individuals to our Board of Directors: Salvatore H. Alfiero, the Chairman and CEO of Mark IV Industries, and Clark A. Johnson, the Chairman and CEO of Pier I Imports. We also said good-bye to Edmund M. Davis, who retired as a company director after 28 years of dedicated service.

Yes, 1998 was quite a year. We substantially resolved the IPP issue, regained our financial footing, reduced prices, improved service, restructured the company, overcame two devastating storms, improved our bond ratings and saw our common stock price appreciate more than 50 percent. But we are not resting here. We still face formidable challenges as we continue to implement *PowerChoice* and stay ahead of the rapid changes occurring in the energy industry.. And we know that we have to work even harder to maximize the value of your investment and to resume a common dividend when conditions allow. On behalf of our outstanding employees who worked so hard and accomplished so much last year, you have our commitment to do all we can to build on the accomplishments of 1998 as we take Niagara Mohawk into the next millennium. □

William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

This year, Niagara Mohawk introduced a new logo, which blends the lettering style used for more than a decade with a central "waterfall" art element in blue. Its overall shape is reminiscent of the company's original logotype. The new logo is the central theme of the cover of this annual report.

As Niagara Mohawk moves into tomorrow's highly competitive markets, having an instantly recognizable, unique brand identity will provide a crucial signpost for consumers. The new logo will help position the company as a modern, competitive player in the energy delivery and energy marketing businesses. It will also create a memorable mark for new customers in new markets who may not be familiar with Niagara Mohawk.

Year 2000 Project

Like all major corporations, Niagara Mohawk is focused on the 'Year 2000' ("Y2K") readiness issue. Please refer to pages 18-20 in this report for a more detailed discussion.

Financial Results

Contents

Market Price of Common Stock and Related Stockholder Matters

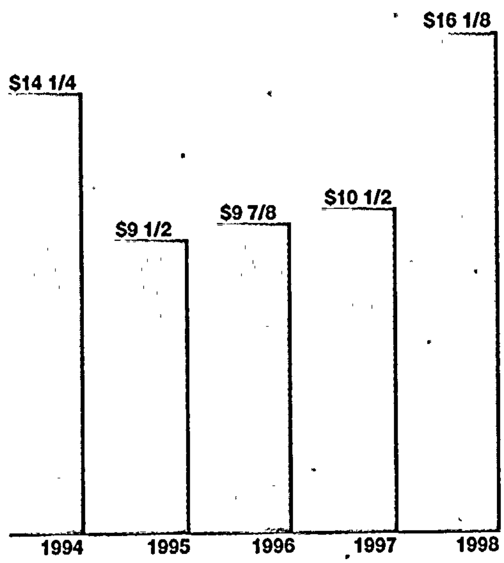
The Company's common stock and certain of its preferred series are listed on the New York Stock Exchange ("NYSE"). The common stock is also traded on the Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges. Common stock options are traded on the American Stock Exchange. The ticker symbol is "NMK."

Preferred dividends were paid on March 31, June 30, September 30, and December 31. During the second quarter of 1998, the Company consummated the MRA agreement. As part of the MRA agreement, the Company made a significant payment to the IPP Parties that resulted in a substantial tax net operating loss. See Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the *PowerChoice* Agreement," and "Financial Position, Liquidity and Capital Resources." As a result of this tax net operating loss, dividends paid in the second, third and fourth quarters of 1998 will constitute a return of capital and only the first quarter dividends are taxable as ordinary income.

The table below shows quoted market prices (NYSE) for the Company's common stock:

	1998		1997	
	High	Low	High	Low
1st Quarter	\$13 9/16	\$10 1/8	\$11 1/8	\$8 1/8
2nd Quarter	15 1/4	11	9	7 7/8
3rd Quarter	16 3/8	14 3/4	10 1/16	8 1/4
4th Quarter	16 1/2	13 15/16	10 9/16	9 1/16

YEAR END PRICE OF COMMON STOCK



For a discussion regarding the common stock dividend, see Management's Discussion and Analysis of Financial Condition and Results of Operations - "Financial Position, Liquidity and Capital Resources - Common Stock Dividend."

Other Company Stockholder Matters. The holders of common stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on preferred stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such preferred stock can elect a majority of the Board of Directors. Whenever dividends on any preference stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect two members to the Board of Directors. No dividends on preferred stock are now in arrears and no preference stock is now outstanding. Upon any dissolution, liquidation or winding up of the Company's business, the holders of common stock are entitled to receive a pro rata share of all of the Company's assets remaining and available for distribution after the full amounts to which holders of preferred and preference stock are entitled have been satisfied.

At the Company's annual meeting on June 29, 1998, the shareholders approved an amendment to the Company's certificate of incorporation to increase the number of authorized shares of common stock to 250 million from 185 million.

After the closing of the MRA (see Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the *PowerChoice* Agreement"), IPP Parties and their designees owned approximately 20.5 million shares of the Company's common stock, representing approximately 11% of the Company's voting securities. Pursuant to the MRA, any IPP Party that received 2% or more of the outstanding common stock and any designee of IPP Parties that received more than 4.9% of the outstanding common stock upon the consummation of the MRA, together with certain but not all affiliates (collectively, "2% Shareholders"), entered into certain shareholder agreements (the "Shareholders Agreements"). Pursuant to each Shareholder Agreement, the 2% Shareholders agree that for five years from the consummation of the MRA, they will not acquire more than an additional 5% of the outstanding common stock (resulting in ownership in all cases of no more than 9.9%) or take any actions to attempt to acquire control of the Company, other than certain permitted actions in response to unsolicited actions by third parties. The 2% Shareholders generally vote their shares on a "pass-through" basis, in the same proportion as all shares held by other shareholders are voted, except that they may vote in their discretion (i) for extraordinary transactions and (ii) for directors when there is a pending proposal to acquire the Company.

The indenture securing the Company's mortgage debt provides that retained earnings shall be reserved and held unavailable for the payment of dividends on common stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. Such provisions have never resulted in a restriction of the Company's retained earnings. This provision will continue to apply to the regulated company under the holding company structure. See "Formation of Holding Company" as discussed below.

As of January 1, 1999, there were approximately 60,000 holders of record of common stock of the Company and about 4,300 holders of record of preferred stock. The chart below summarizes common stockholder ownership by size of holding:

Size of Holding (Shares)	Total Stockholders	Total Shares Held
1 to 99	29,576	761,377
100 to 999	27,862	6,701,542
1,000 or more	2,601	179,901,944
	60,039	187,364,863

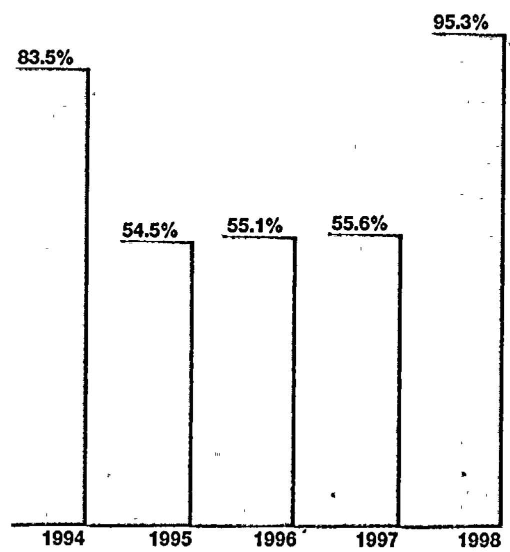
Formation of Holding Company. The *PowerChoice* agreement allows the Company to form a holding company, which the Company's shareholders approved at its 1998 annual meeting. The Company also received approval from the FERC, PSC and NRC, and is awaiting further approval from the Securities and Exchange Commission. Once all approvals are received, a share exchange will occur whereby holders of shares of the Company's common stock will automatically become holders of common stock of Niagara Mohawk Holdings, Inc. ("Holdings") on the basis of one share of common stock for one share of Holdings' common stock. The Company's preferred stock will not be exchanged as part of the share exchange but will continue as shares of the Company's preferred stock. Holdings is authorized to issue 50,000,000 shares of its own preferred stock. The share exchange and the holding company structure will not change the rights of holders of the outstanding shares of the Company's preferred stock. The Company's preferred stock will continue to rank senior to the Company's common stock (which will be held by Holdings) as to dividends and as to distribution of the Company's assets upon any liquidation.

As a result of the share exchange:

- Holdings will become a holding company owned by the former common shareholders of the Company
- Holdings will become the sole owner of the Company's common stock
- The Company's obligations with respect to its long-term debt, First Mortgage Bonds and preferred stock will remain with the Company and not be transferred to Holdings
- The Company will continue to carry on its regulated utility business as a subsidiary of Holdings and the Company's non-regulated subsidiaries will be owned as a separate subsidiary of Holdings. The Company will retain all other subsidiaries.
- The par value per share of Holdings common stock will be $0.01

No income tax gain or loss will be recognized by a holder of the Company's common stock as a result of share exchange solely for Holdings common stock under IRS Code Section 351. The tax basis of the Holdings common stock received in the share exchange will be the same as the exchanging shareholder's basis in the Company's common stock. In addition, no income tax gain or loss will be recognized by the Company or Holdings.

MARKET TO BOOK RATIO



Selected Consolidated Financial Data

The following table sets forth selected financial information of the Company for each of the five years during the period ended December 31, 1998, which has been derived from the audited financial statements of the Company, and should be read in connection therewith. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Notes to Consolidated Financial Statements," the following selected financial data is not likely to be indicative of the Company's future financial condition or results of operations.

	1998	1997	1996*	1995	1994
Operations: (000's)					
Operating revenues	$ 3,826,373	$ 3,966,404	$ 3,990,653	$ 3,917,338	$ 4,152,178
Net income	(120,825)	183,335	110,390	248,036	176,984
Common stock data:					
Book value per share at year end	$16.92	$18.89	$17.91	$17.42	$17.06
Market price at year end	16⅛	10½	9⅞	9½	14¼
Ratio of market price to book value at year end	95.3%	55.6%	55.1%	54.5%	83.5%
Dividend yield at year end	—	—	—	11.8%	7.9%
Basic and diluted earnings per average common share	($0.95)	$1.01	$0.50	$1.44	$1.00
Rate of return on common equity	(5.3)%	5.5%	2.8%	8.4%	5.8%
Dividends paid per common share	—	—	—	$1.12	$1.09
Dividend payout ratio	—	—	—	77.8%	109.0%
Capitalization: (000's)					
Common equity	$ 3,170,142	$ 2,727,527	$ 2,585,572	$ 2,513,952	$ 2,462,398
Non-redeemable preferred stock	440,000	440,000	440,000	440,000	440,000
Mandatorily redeemable preferred stock	68,990	76,610	86,730	96,850	106,000
Long-term debt	6,417,225	3,417,381	3,477,879	3,582,414	3,297,874
Total	10,096,357	6,661,518	6,590,181	6,633,216	6,306,272
Long-term debt maturing within one year	312,240	67,095	48,084	65,064	77,971
Total	$10,408,597	$ 6,728,613	$ 6,638,265	$ 6,698,280	$ 6,384,243
Capitalization ratios: *(including long-term debt maturing within one year)*					
Common stock equity	30.5%	40.5%	39.0%	37.5%	38.6%
Preferred stock	4.9	7.7	7.9	8.0	8.5
Long-term debt	64.6	51.8	53.1	54.5	52.9
Financial ratios:					
EBITDA (000's)	$990.5	$961.5	$957.5	$929.1	$1,029.9
Net cash interest (000's)	$345.5	$226.9	$244.5	$260.5	$ 261.7
Ratio of EBITDA to net cash interest	2.9	4.2	3.9	3.6	3.9
Ratio of earnings to fixed charges	0.57	2.02	1.57	2.29	1.91
Ratio of earnings to fixed charges and preferred stock dividends	0.52	1.67	1.31	1.90	1.63
Other ratios – % of operating revenues:					
Fuel, electricity purchased and gas purchased	39.6%	44.4%	43.5%	40.3%	39.6%
Other operation and maintenance expenses	24.5	21.1	23.3	20.9	23.1
Depreciation and amortization	9.3	8.6	8.3	8.1	7.4
Amortization of the MRA regulatory asset	3.4	—	—	—	—
Federal and foreign income taxes, and other taxes	10.3	15.1	13.6	17.3	14.7
Operating income	4.4	14.1	13.1	17.5	13.3
Balance available for common stock	(4.1)	3.7	1.8	5.3	3.5
Miscellaneous: (000's)					
Gross additions to utility plant	$ 392,200	$ 290,757	$ 352,049	$ 345,804	$ 490,124
Total utility plant	11,431,447	11,075,874	10,839,341	10,649,301	10,485,339
Accumulated depreciation and amortization	4,553,448	4,207,830	3,881,726	3,641,448	3,449,696
Total assets	13,861,187	9,584,141	9,427,635	9,477,869	9,649,816

* Amounts include extraordinary item, see Note 2. Rate and Regulatory Issues and Contingencies.

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

Certain statements included in this Annual Report to Stockholders are forward-looking statements as defined in Section 21E of the Securities Exchange Act of 1934 that involve risk and uncertainty, including the improvement in the Company's cash flow upon the implementation of the MRA and *PowerChoice,* the timing and outcome of the future sale of the Company's fossil, hydro and nuclear generation assets, and the costs and potential recoveries associated with the January 1998 ice storm and September 1998 windstorm. In addition, certain statements made related to the Company's year 2000 program are also forward-looking (see "Year 2000 Readiness Disclosure"). These forward-looking statements are based upon a number of assumptions, including assumptions regarding the *PowerChoice* agreement and regulatory actions to continue to support such an agreement, internal assessment of damage related to the 1998 storms and related government and insurance company's actions with respect to providing recovery for such damage. Actual future results and developments may differ materially depending on a number of factors, including regulatory changes either by the federal government or the PSC, uncertainties regarding the ultimate impact on the Company as the regulated electric and gas industries are further deregulated and electricity and gas suppliers gain open access to the Company's retail customers, challenges to the *PowerChoice* agreement under New York laws, the timing and extent of changes in commodity prices and interest rates, the effects of weather, the length and frequency of outages at the Company's two nuclear plants, the results from the Company's ongoing sale of its generation assets, and the economic conditions of the Company's service territory.

The Company's main business segment is its regulated operations. See Note 11. "Segment Information." This discussion and analysis will concentrate on this business segment unless otherwise noted.

Events Affecting 1998 and the Future

- In early January 1998, a major ice storm caused extensive damage to the Company's facilities in northern New York. The cost to repair damaged facilities was approximately $140 million.
- On March 20, 1998, the PSC approved the *PowerChoice* settlement agreement, which incorporated the terms of the MRA. *PowerChoice* was implemented September 1, 1998 upon PSC approval of rate tariffs.
- At the June 29, 1998 annual meeting, the shareholders gave the Company approval to form a holding company, the implementation of which will occur following the receipt of one final regulatory approval.
- On June 30, 1998, the Company completed $3.8 billion in public financing and used the net proceeds along with shares of the Company's common stock and additional cash to consummate the MRA, which terminated, restated or amended certain IPP power purchase contracts.
- In September 1998, a severe windstorm passed through a portion of the Company's service territory interrupting electric service to more than 250,000 customers. The cost to repair and replace damaged facilities was approximately $22.5 million.
- In December 1998, the Company announced agreements to sell its 72 hydroelectric generating plants for $425 million and its coal-fired electric generating stations for $355 million, which have a combined net book value of $639 million as of December 31, 1998. The Company continues to pursue the sale of its two oil and gas-fired plants and its interest in a third plant.
- In January 1999, the Company announced plans to pursue the sale of its nuclear assets, the Unit 1 nuclear plant and a 41% co-ownership of the Unit 2 plant.

Master Restructuring Agreement and the PowerChoice Agreement

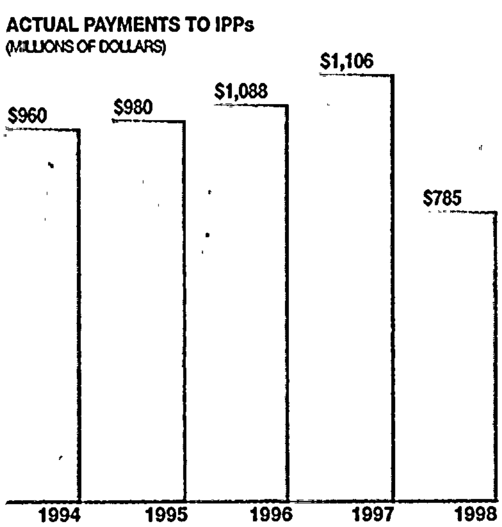
Background. The Company entered into the PPAs that were subject to the MRA because it was required to do so under PURPA and New York State law, which intended to provide incentives for businesses to create alternative energy sources. Under PURPA, the Company was required to purchase electricity generated by qualifying facilities of IPPs at prices that were not expected to exceed the cost that otherwise would have been incurred by the Company in generating its own electricity, or in purchasing it from other sources (known as "avoided costs"). While PURPA was a federal initiative, each state was delegated certain authority over how PURPA would be implemented within its borders. In its implementation of PURPA, the state of New York passed the "Six-Cent Law," establishing 6 cents per KWh as the statutory minimum price for utility purchases of electric power from IPP projects less than 80 MW in size. The Six-Cent Law remained in place until it was amended in 1992 to deny the benefit of the statute to any future PPAs. The avoided cost determinations under PURPA were periodically adjusted by the PSC during this period. PURPA and the Six-Cent Law, in combination with other factors, including the area's existing energy infrastructure and availability of cogeneration hosts, attracted large numbers of IPPs to New York State, and, in particular, to the Company's service territory. The pricing terms of substantially all of the PPAs that the Company entered into in compliance with PURPA and the Six-Cent Law or other New York laws were based, at the option of the IPP, either on administratively determined avoided costs or minimum prices, both of which have consistently been materially higher than the wholesale market prices for electricity.

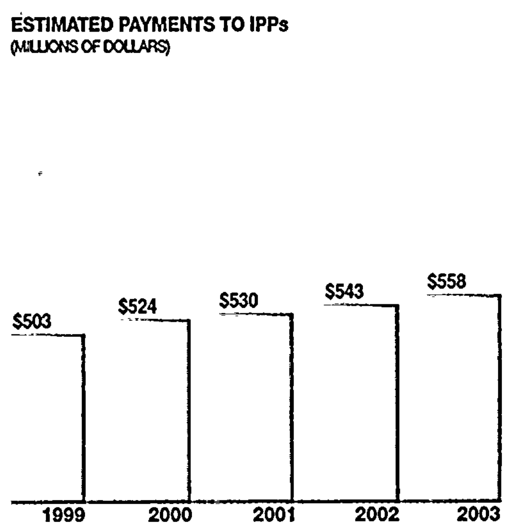
Since PURPA and the Six-Cent Law were passed, the Company was obligated to purchase electricity offered from IPPs in quantities in excess of its own demand and at prices in excess of those available to the Company by internal generation or for purchase in the wholesale market. In fact, by 1991, the Company was facing a potential obligation to purchase power from IPPs substantially in excess of its peak demand of 6,093 MW. As a result, the Company's competitive position and financial performance deteriorated and the price of electricity paid per KWh by its customers rose significantly above the national average. Accordingly, in 1991 the Company initiated a parallel strategy of negotiating individual PPA buyouts, cancellations and renegotiations, and of pursuing regulatory and legislative support and litigation to mitigate the Company's obligation under the PPAs. By mid-1996, this strategy resulted in reducing the Company's obligations to purchase power under its PPA portfolio to approximately 2,700 MW. Notwithstanding this reduction in capacity, over the same period, the payments made to the IPPs in respect of their PPAs rose from approximately $200 million in 1990 to approximately $1.1 billion in 1997 as independent power facilities from which the Company was obligated to purchase electricity commenced operations. The Company estimated that absent the MRA, payments made to the IPPs pursuant to PPAs would have continued to escalate by approximately $50 million per year until 2002.

Recognizing the competitive trends in the electric utility industry and the impracticability of remedying the situation through a series of customer rate increases, in mid-1996, the Company began comprehensive negotiations to terminate, amend or restate a substantial portion of above-market PPAs in an effort to mitigate the escalating cost of these PPAs as well as to prepare the Company for a more competitive environment. These negotiations led to the MRA and the *PowerChoice* agreement.

Master Restructuring Agreement. The MRA was consummated on June 30, 1998 with 14 IPPs. The MRA allowed the Company to terminate, restate or amend 27 PPAs which represented approximately three-quarters of the Company's over-market purchase power obligations. The Company terminated 18 PPAs for 1,092 MW of electric generating capacity, restated eight PPAs representing 535 MW of capacity and amended one PPA representing 42 MW of capacity. The Company paid the IPP Parties an aggregate of $3.934 billion in cash, of which $3.212 billion was obtained through a public market offering of senior unsecured debt, $303.7 million from the public sale of 22.4 million shares of common stock, and the remainder from cash on hand. In addition, the Company issued 20.5 million shares of common stock to the IPP Parties.

Under the PSC approved *PowerChoice* agreement, a regulatory asset was established for the costs of the MRA and will be amortized over a period generally not to exceed ten years. The Company's rates under *PowerChoice* have been designed to permit recovery of the MRA regulatory asset. In approving *PowerChoice*, the PSC limited the estimated value of the MRA regulatory asset that could be recovered, which resulted in a charge to the second quarter of 1998 earnings of $263.2 million upon the closing of the MRA. The *PowerChoice* agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.





The MRA is estimated to reduce the Company's IPP payments by more than $500 million annually, net of purchases of power at market price. The improved cash flow will allow the Company to reduce electricity prices and repay the debt required to finance the MRA. In addition, the Company is actively pursuing other opportunities to reduce its payments to IPPs that were not party to the MRA.

Under the terms of the MRA, the Company has no continuing obligation to purchase energy from the terminated IPP Parties. The restated contracts with eight PPAs reflect economic terms and conditions that are more favorable to the Company than the previous PPAs. The restated contracts have a term of ten years and are structured as indexed swap contracts where the Company receives or makes payments to the IPP Parties based upon the differential between the contract price and a market reference price for electricity. The contract prices are fixed for the first two years changing to an indexed pricing formula thereafter. Contract quantities average 4,100 GWh per year and are fixed for the full ten-year term of the contracts. The indexed pricing structure in combination with the Company's procurement policies ensures that the net price paid for energy and capacity will fluctuate relative to the underlying market cost of gas and general indices of inflation. Until such time as a competitive energy market structure becomes operational in the state of New York, the restated contracts provide the IPP Parties with a put option for the physical delivery of energy. The put energy is to be priced at a market proxy based upon short run marginal cost. Additionally, one PPA representing 42 MW of capacity was amended to reflect a shortened term and a lower stream of fixed unit prices. The Company projects, based upon current projections of future market prices, that it will make the following payments to the IPP Parties under the indexed swap contracts for the years 1999 to 2003 as follows:

Year	*Projected Payment* (in thousands)
1999	$ 97,354
2000	97,688
2001	102,073
2002	103,552
2003	105,531

Although against the Company's forecast of market energy prices the restructured and amended PPAs represent an expected above-market payment obligation, the Company's portfolio of these PPAs provides it and its customers with a hedge against significant upward movement in market prices that may be caused by a change in energy supply or demand. This portfolio contains terms that are believed to be more responsive to competitive market price changes.

PowerChoice Agreement. The *PowerChoice* proposal was originally filed by the Company in October 1995 and subsequent negotiations with PSC Staff and intervenors resulted in the the *PowerChoice* settlement agreement which was filed by the Company in October 1997. The *PowerChoice* agreement, which was approved in the PSC's written order dated March 20, 1998, establishes a five-year rate plan that will reduce class average residential and commercial prices by an aggregate of 3.2% over the first three years, beginning September 1, 1998. The reduction in prices includes certain savings that will result from approved reductions of the New York State GRT. Industrial customers will see average reductions of 25% relative to 1995 tariffs; these decreases will include discounts currently offered to some industrial customers through optional and flexible rate programs. Additionally, in approving *PowerChoice*, which incorporated the terms of the MRA, the PSC made various changes to the settlement agreement. These changes included, among others, exempting certain customers from paying the CTC and requiring the Company to defer savings from the reduction in the interest rate associated with the debt issued in connection with the MRA financing, which have accumulated to $10.7 million through December 31, 1998. The *PowerChoice* agreement measured the 3.2% reduction against 1995 prices. The PSC determined that the percentage reduction should be applied against the lower of 1995 prices or the most current 12-month period. The rates used in the *PowerChoice* implementation on September 1, 1998 are based on the 12-month period ended December 31, 1997 for residential and commercial customers and 1995 prices for all others.

During the term of the *PowerChoice* agreement, the Company would be permitted to defer certain incremental costs associated primarily with environmental remediation, nuclear decommissioning and related costs, and changes in laws, regulations, rules and orders. To date, the Company has not deferred any additional costs other than those stipulated in the *PowerChoice* agreement. In years four and five of its rate plan, the Company can request an annual increase in prices subject to a cap of 1% of the all-in price, excluding commodity costs (e.g., transmission, distribution, nuclear, and forecasted CTC). In addition to the price cap, the *PowerChoice* agreement provides for the recovery of deferrals established in years one through four and, beginning in year four, recover cost variations in the indexed swap contracts resulting from indexing provisions of these contracts. The aggregate of the price cap increase and recovery of deferrals is subject to an overall limitation of inflation.

Under the terms of the *PowerChoice* agreement, all of the Company's customers will be able to choose their electricity supplier in a competitive market by December 1999. Currently, some customers are able to choose their electricity supplier, and the Company expects to offer retail choice to all customers by August 1, 1999. The

Company will continue to distribute electricity through its transmission and distribution systems and will be obligated to be the provider of last resort for those customers who do not exercise their right to choose a new electricity supplier.

The *PowerChoice* agreement provides that the MRA and the contracts executed pursuant thereto are prudent. The *PowerChoice* agreement further provides that the Company shall have a reasonable opportunity to recover its stranded costs, including those associated with the MRA and the contracts executed thereto, through a CTC and, under certain circumstances, through exit fees or in rates for back up service. The Company's rates under *PowerChoice* are designed to permit recovery of the MRA regulatory asset and to permit recovery of, and a return on, the remainder of its assets, as appropriate.

Between the MRA closing date (June 30, 1998) and the *PowerChoice* implementation date (September 1, 1998), the Company experienced a reduction in power purchase costs of $80 million as well as increased financing costs of $40.4 million as a result of the MRA and the MRA financing. The net effect of these items was deferred for future disposition because the time lag between these events was not contemplated in the *PowerChoice* agreement.

In July 1998, the Public Utility Law Project of New York, Inc. ("PULP") and others sought a declaratory judgment, declaring the Company's *PowerChoice* agreement unlawful, null and void and seeking injunctive relief in the Supreme Court of the state of New York, Albany County against the PSC and the Company to enjoin the defendants to halt all their actions and expenditures to implement the rules for the provision of retail energy services contained in the *PowerChoice* agreement. The PSC and the Company filed a motion seeking to dismiss this action. The motion is pending in the Albany County Supreme Court. The Company is unable to predict the outcome of this matter.

In early October 1998, the Alliance for Municipal Power, a group of 21 towns and villages in St. Lawrence and Franklin Counties pursuing municipalization that has also called themselves the Retail Service Communities, and Alfred P. Coppola, a Councilman from the City of Buffalo, commenced an Article 78 Proceeding in Albany County Supreme Court that challenged the PSC's decision to approve *PowerChoice* and the PSC's decision that denied the petitions of Alliance for Municipal Power and Coppola for rehearing before the Commission. The Article 78 Petition seeks to vacate the decision of the PSC approving *PowerChoice* provisions relating to the determination and recovery of strandable costs through the application of a competitive transition charge and exit fees. The PSC has made a motion to dismiss the Article 78 Petition in this matter and the motion is pending in the Albany County Supreme Court. The Company is unable to predict the outcome of this matter at this time. Suspension of *PowerChoice* or renegotiation of its material terms could have a material adverse effect on the Company's results of operations, financial condition, and future cash flows.

In its written Order dated May 6, 1998, the PSC approved the Company's plan to divest all of its fossil and hydro generation assets, which is a key component in the Company's *PowerChoice* agreement to lower average electricity prices and provide customer choice. On December 3, 1998, the Company announced it had reached an agreement with an affiliate of Orion Power Holdings, Inc. ("Orion") to sell its 72 hydroelectric generating plants with a combined capacity of 661 MW for $425 million, representing 1.7 times their book value of approximately $258.2 million at December 31, 1998. As part of the agreement, the Company will purchase electricity from Orion under a transition power agreement ("TPA") through September 2001. On December 23, 1998, the Company announced an agreement with NRG Energy, Inc. ("NRG") to sell its Huntley and Dunkirk coal-fired electric generating stations for $355 million. The coal stations have a book value of approximately $380.6 million and a combined capacity of 1,360 megawatts at December 31, 1998. The Company has also signed, as part of this agreement, a TPA to purchase electricity from NRG through June 2003 at prices consistent with those negotiated in *PowerChoice* for those assets. The TPAs for the hydro and coal-fired facilities are designed to help the Company meet the objectives of rate reduction and price cap commitments as well as meet expected demand as the "provider of last resort" as outlined in the *PowerChoice* agreement. The TPAs act as hedges against rising power costs. The terms of the TPAs provide for both fixed and variable payments, encompassing both capacity and energy. These TPAs are one part of the integrated transactions for the sale of the generating facilities. It is anticipated that transaction closings will occur in mid-1999 after receipt of the necessary regulatory approvals. The Company continues to pursue the sale of its two oil and gas-fired plants in Albany and Oswego, which have net book values of $39.3 million and $332.4 million, respectively at December 31, 1998. The Company is unable to predict the outcome or timing of the divestiture of these plants. The Company will also be selling its interest in the Roseton plant with a net book value of $39.8 million as of December 31, 1998, through an auction by the operator of the plant, Central Hudson Gas and Electric Corporation. Central Hudson Gas and Electric Corporation has indicated that the sale is expected to conclude in 2000. The auction process will serve to quantify any stranded costs associated with the Company's fossil and hydro generating assets. The Company will have a reasonable opportunity to recover these costs through the CTC and otherwise as described above. After the auction process is complete, the

Company has agreed not to own any non-nuclear generating assets in the state of New York, subject to certain exceptions provided in the *PowerChoice* agreement. Under the terms of the note indenture prepared in connection with the financing of the MRA, the Company is obligated to use 85% of the proceeds of the sale of the fossil and hydro generation assets to reduce outstanding debt.

The *PowerChoice* agreement contemplated that the Company's nuclear plants would remain part of the Company's regulated business. The *PowerChoice* agreement stipulates that absent a statewide solution, the Company will file a detailed plan for analyzing other proposals regarding its nuclear assets, including the feasibility of an auction, transfer and/or divestiture of such facilities, within 24 months of *PowerChoice* approval. On January 28, 1999, the Company announced plans to pursue the sale of its nuclear assets. The Company is unable to predict if a sale will occur and the timing of such sale. See "PSC Staff's Tentative Conclusions on the Future of Nuclear Generation."

The *PowerChoice* agreement also allows the Company to form a holding company, which the Company's shareholders approved at its 1998 annual meeting. The Company received approval from the FERC, PSC and NRC to form the holding company. The Company is awaiting further approval from the Securities and Exchange Commission, prior to implementation of the holding company.

The holding company structure is intended to provide the Company and its subsidiaries with the financial and regulatory flexibility to compete more effectively in an increasingly competitive energy industry by providing a structure that can accommodate both regulated and unregulated lines of business. The holding company structure would largely eliminate many regulatory constraints that would limit the Company's ability to participate in unregulated business opportunities as the industry evolves.

All of the foregoing discussion of the *PowerChoice* agreement is qualified in its entirety by the text of the agreement and PSC Order.

For a discussion of the Company's ability to continue to apply SFAS No. 71 to its remaining electric business (nuclear generation and electric transmission and distribution business), under *PowerChoice*, see Note 2. "Rate and Regulatory Issues and Contingencies."

PSC Competitive Opportunities Proceeding - Electric

On May 16, 1996, the PSC issued its Order in the COPS case, which called for a major restructuring of New York State's electric industry, and the introduction of a competitive wholesale power market and retail access for all electric customers. The goals include lowering consumer rates, increasing choice, continuing reliability of service, continuing environmental and public policy programs, mitigating concerns about market power and continuing customer protection and the obligation to serve. The provisions of the Company's *PowerChoice* agreement are consistent with COPS objectives.

The PSC continues to assess other functions in the regulated electric and gas business to lower consumer rates and increase customer choice. The PSC is considering opening competition to such functions as metering, billing, collections and customer service. In addition, on January 13, 1999, the PSC adopted a set of Uniform Business Rules for Retail Access designed to streamline and make more uniform the manner in which the local utilities interact with natural gas and electricity marketers, energy services companies and customers who purchase energy in New York State's evolving competitive market. This was a collaborative effort among all parties involved. The Company will continue to participate with the PSC and other parties as New York State moves forward with a competitive utility industry, but the Company cannot predict the outcome of the results and the impact on its *PowerChoice* agreement.

FERC Rulemaking on Open Access and Stranded Cost Recovery

Rulemaking on Open Access. In April 1996, the FERC issued Order 888. Order 888 promotes competition by requiring that public utilities owning, operating, or controlling interstate transmission facilities file tariffs which offer others the same transmission services they provide for themselves, under comparable terms and conditions. The Company complied with this requirement by filing its open access transmission tariff with FERC on July 7, 1996. Based upon settlement discussions with various parties, a proposed settlement was submitted to the FERC in the first quarter of 1997. The settlement has not been approved by the FERC at this time. Hearings were conducted in September 1997 with non-settling parties. A March 1998 Administrative Law Judge's recommended decision in this proceeding recommended lower tariffs than those filed by the Company. The Company is unable to determine the ultimate resolution of this issue or when a decision will be issued by FERC.

Under FERC Order 888, the NYPP was required to file reformed power pooling agreements that establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. On January 31, 1997, the NYPP Member Systems (the "Member Systems") submitted a comprehensive proposal to establish a NYISO, a New York State Reliability Council ("NYSRC") and a New York Power Exchange ("NYPE") that will foster a fully competitive wholesale electricity market in New York State. The NYISO would provide for the reliable operation of the transmission system in New York State and provide nondiscriminatory open access to transmission services under a single NYISO tariff. Through the NYISO, the transmission owners, including the Company, would be compensated for the use of their transmission systems on a cost-of-service basis. The NYSRC would establish the reliability rules and standards by which the NYISO operates the bulk power system. The NYISO would also administer the daily electric energy market and the NYPE would facilitate the electric energy market on a day-ahead basis.

On June 24, 1998, FERC gave the Member Systems conditional approval to form the NYISO. However, FERC deferred action on the rates, terms and conditions of the NYISO's open access transmission tariff, and directed the Member Systems and interested parties to negotiate a modified voting structure for the NYISO committees. In compliance with this directive, a settlement agreement supported by the Member Systems and a number of parties was submitted to FERC on October 23, 1998. Other steps have also been taken to prepare for the establishment of the NYISO, including selection of members of the Board of Directors. Subsequently, on January 27, 1999, FERC conditionally approved the tariffs, market rules and market based rates proposed by the NYISO. While the Company is unable to predict when FERC will rule on the remaining details of the Member Systems' NYISO proposal, it does believe that progress is being made in New York State toward more competitive wholesale electricity markets, consistent with the *PowerChoice* restructuring agreement.

Stranded Cost Recovery in the Case of Municipalization. In Order 888, the FERC also stated that it would provide for the recovery of prudent and verifiable wholesale stranded costs where the wholesale customer was able to obtain alternative power supplies as a result of Order 888's open access mandate. Order 888 left to the states the issue of retail stranded cost recovery. Where newly created municipal electric utilities required transmission service from the displaced utility, the FERC stated that it would entertain requests for stranded cost recovery since such municipalization is made possible by open access. The FERC also reserved the right to consider stranded costs on a case-by-case basis if it appeared that open access was being used to circumvent stranded cost review by any regulatory agency.

In November 1997, FERC issued Order 888-B. This Order clarified that the FERC recognizes the existence of concurrent state jurisdiction over stranded costs arising from municipalization. The FERC acknowledged in Order 888-B that the states may be first to address the issue of retail-turned-wholesale stranded costs, and stated that it will give the states substantial deference where they have done so.

In approving *PowerChoice*, the PSC authorized changes to the Company's Retail Tariff providing for the recovery of stranded costs in the case of municipalization regardless of whether the new municipal utility requires transmission service from the Company. The calculation of stranded costs is governed by this Retail Tariff, which became effective on April 6, 1998. A number of communities are considering municipalization and have requested an estimate of their stranded cost obligation.

In late January 1997, the Company provided 26 communities in St. Lawrence and Franklin Counties with estimates they requested of the stranded costs they might be expected to pay if they withdrew from the Company's system to create municipal electric utilities. The stranded cost calculations were based on the methodology prescribed by the FERC in Order 888. The preliminary estimate of the combined potential stranded cost liability for the communities ranged from a low of $225 million to a high of $452 million, depending upon the forecast of electricity market prices that was used. These amounts did not include the costs of creating and operating a municipal utility. At this time, it appears that 21 of the original 26 communities are still pursing municipalization. If these 21 communities withdrew from the Company's system, the Company would experience a potential revenue loss of approximately 2% per year.

These 21 communities seeking to withdraw from the Company's system also propose to disconnect entirely from the Company's system and to take transmission service from another utility. They state that, given the provisions of Order 888, FERC would not approve the Company's request for stranded cost recovery under these circumstances. The Company has responded that, regardless of the result at the FERC, those communities will be subject both to the exit fee provisions of the Company's Retail Tariff and the possibility that a state court may permit the Company to recover some or all of the stranded costs in a condemnation proceeding. The 21 communities have filed suit in state court challenging the PSC's approval of the exit fee provisions in the Company's Retail Tariff. The PSC has moved to dismiss the case. The Company is unable to predict the outcome of this matter. See "Master Restructuring Agreement and the *PowerChoice* Agreement."

In August 1997, the Company provided the Village of Lakewood with an estimate of its stranded cost obligation in response to a formal request under FERC Order 888. In June 1998, the Village of Lakewood filed a petition with FERC seeking a determination that it would not be responsible for any of the Company's stranded costs if it created a new municipal electric system. The Company responded in opposition to this petition. On October 1, 1998, FERC set a hearing with a FERC Administrative Law Judge in the matter of Lakewood's stranded cost obligation to the Company under Order 888.

The PSC and the Company requested rehearing of the FERC's Order of October 1, 1998. Both parties pointed out that the PSC has a process in place to adjudicate Lakewood's liability for stranded costs under the

Company's Retail Tariff in the event of municipalization, and suggested that it would be inefficient and contrary to Order No. 888-B for the FERC to hold hearings on Lakewood's stranded cost obligation under Order 888 until Lakewood's stranded cost obligation under the Retail Tariff has been established by the PSC. The Company also sought clarification that Order 888 does not preempt the PSC's jurisdiction to authorize the recovery of stranded costs under the exit fee provisions of the Company's Retail Tariff.

On December 11, 1998 the FERC issued an order granting the Company's request for clarification that Order 888 does not preempt the exit fee provision of the Retail Tariff and directing that the Lakewood case be held in abeyance pending the resolution of Lakewood's stranded cost obligation under the Company's Retail Tariff. Lakewood and the Company are required to file a joint status report with FERC six months from the issuance of the Order. On January 7, 1999, the PSC directed the Company to provide Lakewood, within 45 days, an estimate of Lakewood's stranded cost obligation under the exit fee provisions of the Company's Retail Tariff. On February 18, 1999, the Company provided Lakewood with an estimate of these exit fees of $14.98 million. The Company is unable to predict the outcome of this matter.

On December 7, 1998, the Company provided the City of Buffalo with both a PSC exit fee estimate and FERC Order 888 estimate of its stranded cost obligation. The PSC exit fee estimate is $899 million and the FERC Order 888 estimate is $1.5 billion. If the City of Buffalo withdrew from the Company's system, the Company would experience a potential revenue loss of approximately 8% per year. The Company has also prepared exit fee stranded cost estimates for annexations in the Village of Wellsville and Madison County. The Company is unable to predict whether the City of Buffalo or these other municipalities will pursue withdrawal from the Company's system or the amount of stranded costs the Company may receive as a result of any withdrawals.

Other Federal and State Regulatory Initiatives

Multi-Year Gas Rate Settlement Agreement. The Company, Multiple Intervenors (an unincorporated association of approximately 60 large commercial and industrial energy users with manufacturing and other facilities located throughout New York State) and PSC staff reached a three-year settlement that was conditionally approved by the PSC on December 19, 1996. The settlement rate has the effect of a $10 million annual reduction in base rates or a $30 million total reduction over the three-year term of the settlement. This reflected a $19 million reduction in the amount of fixed non- commodity costs to be recoverable in base rates, offset by a $9 million increase in annual base rates. The Company estimated that the combination of in-hand supplier refunds and further reductions in upstream pipeline costs would be sufficient to fund the $19 million annual reduction in non-commodity cost recovery.

If the non-commodity cost reductions exceed $57 million ($19 million annually) during the three-year settlement period, the excess, up to $40 million will be credited to a Contingency Reserve Account ("CRA") to be utilized for ratepayer benefit in the rate year ending October 31, 2000 or beyond. To the extent the actual non-commodity cost reductions exceed $57 million by more than $40 million, the Company may retain any excess subject to a return on equity sharing provision. In the event the non-commodity reductions fall short of the $57 million estimate, the Company will bear the risk of any shortfall. As of December 31, 1998, the Company has credited $30 million to the CRA. With respect to the second year of the gas rate settlement agreement (November 1, 1997 to October 31, 1998), the Company did not experience any margin (revenues less fuel costs) or peak shaving losses, since the terminating and restructuring IPPs ran longer than originally anticipated. However, the Company may experience margin or peak shaving losses in the last year of the settlement, a result of the termination or restructuring of IPP contracts. The margin losses would be collected currently subject to 80 percent/20 percent (ratepayer/shareholder) sharing and the peak shaving losses will be deferred to the CRA, subject to limits specified in the settlement.

In return for taking on this risk, the Company has achieved a portion of the revised rate structure that had been proposed, such that the Company is allowed to recover more of its costs through the customer basic service charge and less on the customer usage charge, which fluctuates based on volume. The Company obtained an ROE cap of 13.5% with 50/50 sharing between ratepayers and shareholders in excess of the cap. The company has not achieved an ROE exceeding the cap in the rate years ending October 31, 1997 or 1998. The Company also has an opportunity to earn up to $2.25 million annually if its gas commodity costs are lower than a market based target without being subject to the ROE cap. The Company has an equal $2.25 million risk if gas commodity costs exceed the target. An additional major benefit of the revised rate design is that the margin made on each additional new customer will significantly increase to the extent additional throughput does not require additional upstream pipeline capacity for service. This, along with the approval of the Company's Progress Fund, which allows the Company to use utility revenues in an amount not to exceed $11 million in total for the purpose of providing financing for large customers to convert or increase their gas use, will provide new opportunities for growth.

Future of the Natural Gas Industry. In November 1998, the PSC issued its Policy Statement concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment (PSC Policy Statement). The PSC Policy Statement noted the following:

- The PSC envisions a transitional time frame of three to seven years for local gas distribution companies (LDC) to exit the business of purchasing natural gas (the "merchant" function).
- The PSC envisions a process comprising three basic elements, which should be pursued in parallel in the exiting of the merchant function:
  1. Addressing the issues involved in the exiting of the merchant function on a utility-by-utility basis as part of the LDCs individual rate plans;
  2. Collaboration among staff, LDCs, marketers, pipelines and other stakeholders of generic issues such as operational and reliability issues, protocols and information systems requiring a status report by April 1, 1999; and
  3. Coordination of issues faced by electric utilities, including provider of last resort issues and a plan to allow competition in other areas, such as metering, billing and information services.
- LDCs may no longer require capacity assignment or inclusion of capacity costs in transportation rates beyond April 1, 1999 to customers migrating to marketers except where specific operational and reliability requirements warrant.

In November 1998, the PSC approved the Company's proposed pilot program that would, effective December 1, 1998, no longer require assigning pipeline capacity and related costs upstream of the CNG Transmission System to customers migrating to transportation. However, the Company's proposed pilot program sought to continue to assign capacity on the CNG system until October 31, 1999, the expiration date of its current gas rate settlement agreement. A stranded cost recovery mechanism, in the form of a surcharge, was established to provide for the recovery of the unassigned pipeline capacity costs until October 31, 1999.

In December 1998, the Company notified the PSC that the Company's specific operational and reliability requirements continue to warrant certain mandatory capacity assignment and inclusion of capacity costs in transportation rates after April 1, 1999. The PSC noted in its PSC Policy Statement that it will provide LDCs with a reasonable opportunity to recover these strandable costs if they can demonstrate compliance with the PSC's directives to minimize such costs. The Company believes that it has taken numerous actions to reduce its capacity obligations and its potential stranded costs, but is unable to predict the outcome of this matter. The Company anticipates that this issue will be addressed in the individual negotiations with the PSC anticipated to begin during the second quarter of 1999. For a discussion of the Company's long term supply, transportation and storage commitments, see Note 9. "Commitments and Contingencies."

NRC Policy Statement and Amended Decommissioning Funding Regulations. The NRC issued a policy statement on the Restructuring and Economic Deregulation of the Electric Utility Industry (NRC Policy Statement) in 1997. The NRC Policy Statement addresses the NRC's concerns about the adequacy of decommissioning funds and about the potential impact on operational safety. In addition to the NRC Policy Statement, the NRC amended its regulations on decommissioning funding to reflect conditions expected from deregulation of the electric power industry.

The NRC's new decommissioning funding rule, which addresses concerns about the adequacy of decommissioning funds, took effect on November 23, 1998. The NRC's new rule and its accompanying standard review plan, which is still pending NRC review, could raise compliance issues. Licensees that are no longer subject to traditional cost-of-service regulation for 80% or less of their electricity sales will need to assure that they have a source of revenue for decommissioning funds through a non-bypassable charge which qualifies a licensee to use a sinking fund. See Note 3. "Nuclear Operations" for a discussion of the Company's decommissioning estimates for Unit 1 and Unit 2.

NRC and Nuclear Operating Matters. In January 1998, the NRC issued its Systematic Assessment of Licensee Performance ("SALP") report on Unit 1 and Unit 2, which covers the period June 1996 to November 1997. The SALP report, which is an extensive assessment of the plants' performance in the areas of operations, maintenance, engineering and support, stated that the performance of Unit 1 and Unit 2 was generally good, although ratings were lower than the previous assessment. The Company agrees with the NRC's determination that there are areas of its performance that need improvement and has taken several actions to make those needed improvements.

Some owners of older General Electric Company boiling water reactors, including the Company, have experienced cracking in horizontal welds in the plants' core shrouds. In response to industry findings, the Company installed pre-emptive modifications to the Unit 1 core shroud during a 1995 refueling and maintenance outage. The core shroud, a stainless steel cylinder inside the reactor vessel, surrounds the fuel and directs the flow of reactor water through the fuel assemblies. Inspections conducted as part of the March 1997 refueling and maintenance outage detected cracking in vertical welds not reinforced by the 1995 repairs. Subsequently, the Company filed a comprehensive inspection and analysis report with the NRC that concluded that the condition of the Unit 1 core shroud supports the safe operation of the plant, and currently has NRC approval to operate Unit 1 until the Unit's scheduled refueling and maintenance outage in spring 1999, at which time the core shroud will be reinspected. The Company has developed a repair that would be accomplished during the spring 1999 outage if inspections indicate that repairs are needed.

On May 2, 1998, Unit 2 was taken out of service for a planned refueling and maintenance outage. During the outage the Company performed scheduled inspections of the plant's reactor core shroud and identified cracking in the welds of the shroud. The scope of the inspection was expanded once the cracking was found, which extended the length of outage. The NRC staff agreed that continued operation without repair or intermediate inspection of the core shroud is acceptable for at least one operating cycle after completion of the May 1998 refueling outage. Unit 2 returned to service on July 5, 1998 after completing the 64-day refueling and maintenance outage.

PSC Staff's Tentative Conclusions on the Future of Nuclear Generation. On August 27, 1997, the PSC requested comments on its staff's tentative conclusions about how nuclear generation should be treated after decisions are made on the individual electric restructuring agreements. The PSC staff concluded that beyond the transition period (the period covered by the various New York utility restructuring agreements, including *PowerChoice*), nuclear generation should operate on a competitive basis.

In October 1997, the majority of utilities with interests in nuclear power plants, including the Company, requested that the PSC reconsider its staff's nuclear proposal, and the utilities recommended that a more formal process be developed to address issues relating to competition, sale of nuclear plants, responsibility for decommissioning, disposal of spent fuel, safety, and environmental benefits of fuel diversity.

On March 20, 1998, the PSC issued an opinion and order instituting a further inquiry into the matters addressed in the PSC Staff's tentative conclusions regarding the treatment of nuclear generation in the future. The order concluded that the proposals contained in the Staff Report required more extensive examination, and directed that the examination begin with a collaborative process and move to litigation on particular issues if necessary. A collaborative proceeding commenced on January 20, 1999.

The matters addressed in the inquiry include:

- Market treatment for nuclear power
- The feasibility of mandated divestiture and its likely consequences
- Decommissioning issues
- Effects of PSC Staff's proposal on municipalities

The tentative time line established by PSC Staff for this inquiry calls for completion of the process by the end of 1999.

In January 1999, the Company announced plans to pursue the sale of its nuclear assets, which will require approval from the PSC. The Company is unable to predict if a sale will occur and the timing of such sale.

At December 31, 1998, the net book value of the Company's nuclear generating assets was approximately $1.6 billion, excluding the reserve for decommissioning. In addition, the Company has other assets of approximately $0.5 billion. These assets include the decommissioning trusts and regulatory assets, primarily due to the deferral of income taxes.

Other Company Efforts to Address Competitive Challenges

Tax Initiatives. The Company is working with utility, customer and state representatives to solve the negative impact that all utility taxes, including the GRT, are having on rates and the state of the economy. At the same time, the Company is also contesting the high real estate taxes it is assessed by many taxing authorities, particularly those imposed upon generating facilities.

The New York State Legislature passed a state budget in August 1997 which includes a reduction of the GRT over three years. For gas and electric utilities, the tax imposed on gross income was reduced from 3.5% to 3.25% on October 1, 1998 and from 3.25% to 2.5% on January 1, 2000. The state tax imposed on gross earnings will remain unchanged at .75%, bringing the total GRT to 3.25% — a full percentage point lower than 1997's level of 4.25%. As contemplated in *PowerChoice*, the savings from the reduction of the GRT will be passed on to the Company's customers. The Company believes that further tax relief is needed to relieve the Company's customers of high energy costs and to improve New York State's competitive position as the industry moves toward a competitive marketplace.

The following table sets forth a summary of the components of other taxes (exclusive of income taxes) incurred by the Company in the years 1996 through 1998:

	In millions of dollars		
	1998	1997	1996
Property tax expense	$251.1	$250.7	$249.4
Sales tax	17.6	13.4	14.1
Payroll tax	37.4	34.1	36.4
Gross Receipts tax	167.0	184.6	184.1
Other taxes	0.3	0.1	0.5
Total tax expense	473.4	482.9	484.5
Charged to construction, subsidiaries and regulatory recognition	(13.4)	(11.4)	(8.7)
Total other taxes	$460.0	$471.5	$475.8

Customer Discounts. In recent years, as energy prices have risen, customers have found alternatives to electric service from their host utility, including the Company. To address that competitive challenge, the Company filed for a service tariff in 1994 called SC-11. The SC-11 tariff provided the Company with flexibility to individually negotiate service agreements within the Company's service franchise territory in response to a number of competitive alternatives such as on-site generation, fuel switching, and facility relocation.

Effective September 1, 1998, the Company's *PowerChoice* agreement was implemented. As part of that agreement, the PSC approved several key pricing initiatives to address the Company's price levels and the resulting need to provide discounted service. Those initiatives include:

- Service class specific pricing goals were agreed upon (see "Master Restructuring Agreement and the *PowerChoice* Agreement"). The targeted rate redesigns contained in *PowerChoice* are intended to deliver the greatest price reductions to those customers who have exhibited the greatest competitive challenges to the Company under SC-11. The rate design provides the most competitive prices to customers who provide economic value to the state because they use the greater amounts of electricity and have the greater demand on the Company's system, thereby minimizing the need (and amount) of future discounts, while maximizing the incentive to remain in New York State. In addition, the pricing goals include those discounts forecasted under SC-11.
- The PSC agreed to close SC-11 to new subscriptions provided that the Company agrees to honor all existing contracts through their natural expiration date, provide a provision for limited renewal of expiring SC-11 agreements and develop a suitable replacement tariff. Therefore, as contracts expire, customers will either migrate back to the redesigned standard tariff rate classification or continue on the SC-11 agreement.
- A new service tariff, SC-12, has been approved as a replacement tariff to SC-11 and will address future competitive challenges for the Company. SC-12 is differentiated from SC-11 in that predetermined minimum criteria are specified within the tariff along with standardized discounted pricing which varies according to the underlying competitive challenge which the Company is facing. The Company has also retained flexibility to address specific competitive challenges for energy intensive and job intensive challenges through individual negotiations.
- Revisions were made to the Company's back up, supplemental, and maintenance pricing tariff for customers installing on-site generation. The Company has been trying to establish compensatory rates for these services for a number of years. A tariff provision resulting from *PowerChoice* ensures that the Company can charge compensatory rates for these services and thereby reduce the discounts that would otherwise be necessary in its absence.

Together, these initiatives will provide lower overall prices to customers, strengthen the Company's competitive position and minimize the amount of future discounts during the term of *PowerChoice*.

Year 2000 Readiness Disclosure

As the year 2000 approaches, the Company, along with other companies, could experience potentially serious operational problems, since many computer programs that were developed in the past may not properly recognize calendar dates beginning with year 2000. Further, there are embedded chips contained within generation, transmission, distribution, gas, and other equipment that may be date sensitive. In circumstances where an embedded chip fails to recognize the correct date, electric, gas and business operations could be adversely affected.

Plan: A Company-wide year 2000 project management office has been formed and year 2000 project managers have been appointed within each business group. A year 2000 program vice-president and an executive level steering committee have been put in place to oversee all aspects of the program. In addition to Company personnel, the Company has retained the services of leading computer service and consulting firms specializing in computer systems and embedded components, which are involved in various phases of the project. Also, the Company is working closely with industry groups such as the Electric Power Research Institute ("EPRI"), North American Electric Reliability Council ("NERC"), Nuclear Energy Institute, and other utilities. In addition, the PSC is requiring that New York utilities have mission critical year 2000 work, including a contingency plan, completed by July 1, 1999, and the NRC is requiring the Company to certify that the Company's two nuclear plants will be year 2000 ready by July 1, 1999. A plan was developed that established phases of the work to be done. The phases are:

- an inventory of all systems and equipment, (including a physical walk-down of all of the Company's substations),
- an assessment of all systems and equipment and definition of next steps,
- remediation,
- testing and validation,
- acceptance and deployment,
- independent validation, and
- contingency planning.

As part of the inventory phase, all the systems and equipment have been prioritized into four categories based upon their functional need and importance. The priorities are:

- Priority 1 - Any failure or regulatory breach that can cause an interruption to the generation or delivery of electric or gas energy to customers, or can jeopardize the safety of any employee, customer, or the general public (e.g. the Energy Management System that controls the flow of electricity and communicates information between the control center and sub-stations).
- Priority 2 - Any failure that can cause an interruption to customer service or breach of significant contractual or financial commitment (e.g. Meter reading equipment).
- Priority 3 - Any failure that can inconvenience a business partner or significantly impact a Company business group productivity (e.g. electronic payments to vendors).
- Priority 4 - Any failure that can adversely impact a Company work group or personal productivity, or other business processes (e.g. applications used on a desktop computer used to accomplish day-to-day productivity activities).

Although the Company has identified seven different phases of the project, in some cases the phases are done concurrently. For example, individual computers may be completely tested and redeployed while others are still being remediated. Information obtained within the phases is reviewed by a panel consisting of employees and consultants. Additional testing may be performed based on the importance of the component and a recommendation of the panel. Complete integration and interface testing will be performed on components and systems whenever possible.

The Company's primary focus is on priorities 1 and 2 because of the direct impact on customers. Although the Company's plan addresses completion of all priority items prior to July 1, 1999, some exceptions may not be addressed completely. These are scheduled, however, to be completed by January 1, 2000.

The Company's progress with its year 2000 issues for priority items 1 and 2 are as follows:

Phase	Status	Estimated Completion Date
- Inventory	Complete	
- Assessment	Complete	
- Remediation	In-progress	December 1998 - May 1999
- Testing & Validation	In-progress	March 1999 - May 1999
- Acceptance	In-progress	March 1999 - June 1999
- Independent Validation	In-progress	October 1999
- Contingency Planning	In-progress	December 1998 - June 1999

Note: Each business group within the Company has its own schedule. The estimated completion dates above may show a range due to different schedules within each business group.

The Company has expanded the scope of its Independent Validation phase and has added an additional Quality Assurance Audit scheduled for September 1999. Therefore, the Company has extended its estimated completion date for that phase to October 1999.

Risks: The failure to correct for year 2000 problems, either by the Company or third parties, could result in significant disruptions of the Company's operations. At this point in time based on the Company's progress to date and the information received from third parties, the Company is unable to determine its most reasonably likely worst case scenario.

Like any organization, the Company is dependent upon many third parties, including suppliers of energy and materials (e.g. independent power producers), service providers, transporters, and the government. These third parties provide services vital to the Company and year 2000 problems at these companies could adversely affect electric and gas operations. One such example is that the Company expects that by the year 2000, it will be purchasing the majority of its electric generation needs. If any of these suppliers has a year 2000 failure, it could interrupt energy supply to the Company's customers. Another example of such a vital third party is telephone companies. If the telephone companies have year 2000 failures, this could in turn affect the Company's customer response capabilities and the Company's ability to operate and maintain the transmission and distribution system that carries electricity to businesses and customer homes. To address these third party issues, the Company has requested certificates of compliance from third parties. To date, the Company has received some responses, but disclosure has been limited. The Company will continue to follow up with third parties to verify the accuracy of responses when the Company's relationship with such third parties is material for its operations. However, the Company may not be able to verify accuracy in all cases. The inability of suppliers to complete their year 2000 readiness process could materially impact the Company.

The Company is connected to an electric grid that links utilities throughout the United States and Canada. This interconnection is essential to the reliability and operational integrity of the connected utilities. If one of the electric utilities in the grid has a failure, it could cause power fluctuations and possible interruption of others in the grid. As a result, even when the Company does an effective job of becoming compliant, it could still have customer interruptions. The Company is working closely with NYPP, NERC, other utilities, EPRI, and other industry groups to address the issue of grid reliability.

The Company's gas distribution system also has the potential to be adversely impacted by year 2000 noncompliance either by third parties or if the Company's program fails to identify and remediate all problem areas. From the third party natural gas production and transmission facilities, to the Company's distribution pipeline system, and ultimately, to the customer, there are computer systems and equipment with date sensitive processing. If, despite the Company and third party's best efforts, a year 2000 failure occurs, the flow of gas to the customer could be jeopardized.

As an example, the Company is connected directly to three major transmission pipelines, and has an indirect connection with a fourth. If these pipelines are unable to provide full gas delivery to the Company, the Company would implement standing emergency procedures that could interrupt customers. To avoid such an event, the Company is working with the pipelines, and state agencies to reduce the probability of any customer interruptions due to year 2000 problems.

Contingency Plans: The Company's year 2000 schedules also include the development and implementation of contingency plans in the event of year 2000 failures, both within the Company and by third parties. The Company expects to have these plans completed during 1999 for all priority categories. The Company has established a year 2000 Contingency Planning department to oversee and assist the business groups in the creation of their contingency plans. The contingency plans will vary by business group and by the various priority levels for different systems and equipment. A schedule has been created to track progress, which includes participation in the NERC drills scheduled for April 1999 and September 1999.

Costs: The Company estimates that total program costs will approximate $33.3 million of which approximately $23.3 million will be expensed and $10 million will be capitalized. Total program costs incurred through December 31, 1998 are $11.6 million of which $8.0 million was expensed and $3.6 million was capitalized. The Company expects to fund the total program costs through operating cash flows.

Over the last several years as the Company implemented various large computer projects, the Company was conscious of year 2000 exposures and therefore made sure the projects were year 2000 compliant. However, these computer projects were implemented for business reasons rather than to solely comply with year 2000 issues. These projects included replacing the customer service/billing/revenue system, as well as implementing a project accounting system, a computer aided dispatch system, and desktop computers for employees, among others. Through December 31, 1998, the Company has spent approximately $70 million on these projects in addition to specific year 2000 compliance spending. The Company has not deferred any significant computer projects as a result of the year 2000 project.

Certain statements included in this discussion regarding year 2000 compliance are forward-looking statements as defined in Section 21E of the Securities Exchange Act of 1934. These statements include management's best estimates for completion dates for the various phases and priorities, testing to be performed, costs to be spent for compliance, and the risks associated with non-compliance either by the Company or third parties. These forward-looking statements are subject to various factors, which may materially affect the Company's efforts with year 2000 compliance. Specific factors that might cause such material differences include, but are not limited to, the availability and cost of personnel trained in this area, which could cause a change in the estimated completion date of a particular phase, the ability to locate and correct all relevant software and embedded components, the compliance of critical vendors, as well as neighboring utilities, and similar uncertainties. The Company's assessments of the effects of year 2000 on the Company are based, in part, upon information received from third parties and other utilities, and the Company's reasonable reliance on that information. Therefore, the risk that inaccurate information is supplied by third parties and other utilities upon which the Company reasonably relied must be considered as a risk factor that might affect the Company's year 2000 efforts. The Company is attempting to reduce the risks by utilizing an organized approach, extensive testing, and allowance of ample contingency time to address issues identified by tests.

1998 Storms

In early January 1998, a major ice storm and flooding caused extensive damage in a large area of northern New York. The Company's regulated electric transmission and distribution facilities in an area of approximately 7,000 square miles were damaged, interrupting service to approximately 120,000 of the Company's customers, or approximately 300,000 people. The Company had to rebuild much of its transmission and distribution system to restore power in this area. By the end of January 1998, service to all customers was restored.

The total estimated cost of the restoration and rebuild efforts is approximately $140.5 million. As of December 31, 1998, the Company expensed $72.9 million associated with the January 1998 ice storm (of which $62.1 million was considered incremental) and capitalized $67.6 million of costs as utility plant.

The Company continues to pursue federal disaster relief assistance. The Company has submitted claims to its insurance carriers for hydroelectric stations and substations damages, and for electric transmission and distribution damages. In December 1998, the Company received a $2 million advance payment from one of its insurance carriers. The Company is unable to determine the total amount of recoveries it may receive from these sources.

On September 7, 1998 a severe windstorm passed through a portion of the Company's service territory interrupting electric service to more than 250,000 customers from Niagara Falls to Albany. Power was restored to the majority of the customers within one week. The total preliminary estimated cost of restoration from the September storm is approximately $22.5 million. However, final costs of the storm will not be known until all costs and charges are analyzed and charges from other utilities and contractors have been received. As of December 31, 1998, the Company recorded $19.2 million in expense (of which $15.7 million was considered incremental). The remaining $3.3 million has been capitalized. The Company is continuing to inspect and survey the work completed. The Company will pursue federal disaster relief assistance for the September storm.

Results of Operations

The Company experienced a loss in 1998 of $157.4 million or 95 cents per share, as compared to earnings of $145.9 million, or $1.01 per share, in 1997 and earnings of $72.1 million, or 50 cents per share, in 1996.

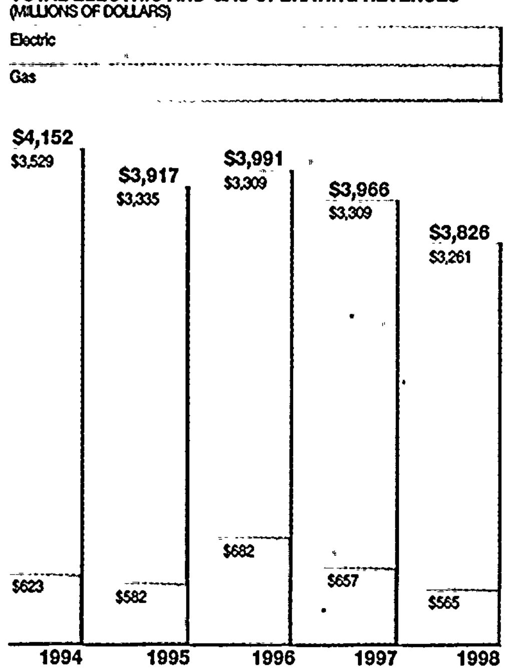
Results for 1998 were negatively impacted by a non-cash write-off of $263.2 million or $1.03 per share associated with the portion of the MRA regulatory asset disallowed in rates by the PSC and by the regulatory treatment of the MRA regulatory asset (see Master Restructuring Agreement and the *PowerChoice* Agreement). With the consummation of the MRA and implementation of *PowerChoice* effective September 1, 1998, the Company expects reported earnings for the next five years to be substantially depressed as a result of the regulatory treatment of the MRA regulatory asset (see Note 2. Rate and Regulatory Issues and Contingencies). The January 1998 ice storm and the September 1998 windstorm also negatively impacted 1998 earnings by $77.8 million, or 30 cents per share, which reflects the Company's estimate of incremental, non-capitalized costs to restore power and rebuild its electric system. In addition, per share results for the year ended December 31, 1998 were diluted by the issuance of 42.9 million shares of common stock in connection with the MRA.

Earnings in 1996 were reduced by an after-tax write-off of $67.4 million, or 47 cents per share, associated with the discontinued application of regulatory accounting principles to the Company's fossil and hydro generation business. Largely as a result of the Company's 1996 assessment of the increased risk of collecting significantly higher levels of past-due customer bills, bad debt expense in 1996 was higher than in 1997 by $81.1 million, reducing earnings in 1996, compared to 1997, by 37 cents per share. However, earnings in 1996 were aided by a $15 million after-tax gain on the sale of a 50 percent interest in CNP which added 10 cents per share to 1996 earnings. Industrial customer discounts not recovered in rates in 1997 exceeded 1996 levels by $25.2 million, reducing 1997 earnings by 11 cents per share. In addition, a decline in higher-margin residential sales also adversely impacted 1997 earnings. The lower-margin industrial-special sales (sales by the Company on behalf of NYPA), as well as, industrial sales increased. As a result, 1997 total public sales were essentially the same as sales in 1996.

The Company's 1998 earned ROE was -5.3% as compared to 5.5% in 1997 and 2.8% (5.4% before extraordinary loss) in 1996. The Company's ROE authorized in the 1995 or last rate setting process is 11.0% for the electric business and 11.4% for the regulated gas business. No specific ROE percentage was established under *PowerChoice*.

The following discussion and analysis highlights items that significantly affected primarily the regulated operations during the three-year period ended December 31, 1998. This discussion and analysis is not likely to be indicative of future operations or earnings, particularly in view of the consummation of the MRA and implementation of *PowerChoice*. It also should be read in conjunction with the Financial Statements and other financial and statistical information appearing elsewhere in this report.

TOTAL ELECTRIC AND GAS OPERATING REVENUES
(MILLIONS OF DOLLARS)



Regulated Segment Revenues and Sales

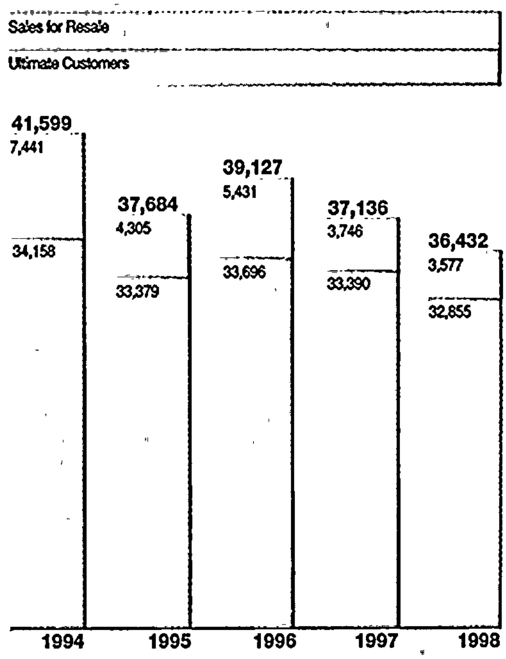
Regulated electric revenues for 1998 were $3,261 million and were $3,309 million in both 1997 and 1996. Revenues in 1997 and 1996 were the same in aggregate with variances between customer groups.

The $48.3 million or 1.5% decrease in 1998 regulated electric revenues was primarily due to a decrease in volume and mix of sales of $44.4 million along with rate reductions under *PowerChoice*. The decrease was partially offset by increases in sales of energy to other electric systems. Under *PowerChoice*, revenues may decline further as customers choose alternative suppliers. However, the Company will recover stranded costs through the CTC. See "Master Restructuring Agreement and the *PowerChoice* Agreement."

During 1997, FAC revenues increased $42.8 million, primarily as a result of the Company's ability in 1997 to recover increased payments to the IPPs through the FAC. However, this increase was offset by a decrease in revenues from sales to other electric systems and lower electric sales due to warmer weather.

Regulated Electric Revenues	Increase (decrease) from prior year (in millions of dollars) 1998	1997	1996
Fuel adjustment clause revenues..	$ (4.7)	$ 42.8	$ 38.1
Changes in volume and mix of sales to ultimate consumers....	(44.4)	(12.7)	(57.1)
Sales to other electric systems....	11.0	(29.6)	(18.6)
PowerChoice rates..............	(10.2)	—	(10.2)
	$(48.3)	$ 0.5	$ (47.8)

ELECTRIC SALES (GWHRS)



The FAC has been eliminated under the *PowerChoice* agreement. Changes in FAC revenues generally were margin-neutral (subject to an incentive mechanism discussed in - Note 1. "Summary of Significant Accounting Policies"), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices, generally resulted in low margin contributions to the Company. Thus, fluctuations in these revenue components generally did not have a significant impact on net operating income. With *PowerChoice*, the Company is no longer subject to regulatory sharing mechanisms for sales to other utilities and transmission revenues.

Regulated electric kilowatt-hour sales were 36.4 billion in 1998, 37.1 billion in 1997 and 39.1 billion in 1996. The 1998 decrease of 0.7 billion KWh, or 1.9% as compared to 1997, is related primarily to a 4.5% decrease in sales to other electric systems. See Regulated Electric and Gas Statistics - "Regulated Electric Statistics." Sales to ultimate consumers also decreased in 1998 primarily due to warmer weather during the winter months. After adjusting for the effects of weather and the farm and food processor retail access pilot program (which the pilot program has the effect of reducing sales to ultimate consumers), sales to ultimate consumers would have expected to increase 0.4%. The 1997 decrease of 2.0 billion KWh, or 5.1% as compared to 1996, primarily reflects a 31.0% decrease in sales to other electric systems.

Details of the changes in regulated electric revenues and KWh sales by customer group are highlighted in the table below:

Class of service	1998 % of Electric Revenues	% Increase (decrease) from prior year 1998 Revenues	1998 Sales	1997 Revenues	1997 Sales
Residential..................	36.9%	(2.1)%	(2.6)%	(2.0)%	(2.0)%
Commercial..................	37.4	(1.1)	0.1	(0.3)	(0.1)
Industrial....................	14.7	(9.5)	(4.8)	1.2	0.6
Industrial – Special...........	2.0	3.3	1.4	5.8	4.2
Municipal service.............	1.7	1.1	2.6	1.4	(4.5)
Total to ultimate consumers	92.7	(2.8)	(1.6)	(0.6)	—
Other electric systems.........	2.9	13.1	(4.5)	(26.1)	(31.0)
Miscellaneous................	4.4	23.2	—	70.4	(100.0)
Total....................	100.0%	(1.5)%	(1.9)%	—%	(5.1)%

As indicated in the table below, regulated electric fuel and purchase power costs decreased in 1998 by 12.3% or $173.6 million. The decrease is mainly the result of decreased purchases from the IPPs of $321.9 million. Of this amount, $80 million relates to net reductions in purchases from IPP Parties for the period between the closing of the MRA to the *PowerChoice* implementation date, which were deferred for future rate making disposition because the time lag between these events was not contemplated in the *PowerChoice* agreement. The decrease in IPP purchases is primarily the result of the MRA agreement which resulted in the termination of 18 PPAs for 1,092 MW, restatement of eight PPAs for 535 MW and the amendment of one PPA for 42 MW. Other purchased power costs decreased $8.2 million. As a result, the Company's load requirements were met to a greater extent from internal sources, which resulted in an increase in fuel costs of $58.9 million as compared to 1997.

Internal generation decreased 10.1% in 1997 principally due to the outage at Unit 1 and a reduction in hydroelectric power as a result of lower than normal precipitation in the summer months. In 1997, Unit 1 was out of service for 153 days, due to a planned refueling and maintenance outage (which took 68 days) and for the emergency condenser replacement (which took approximately 85 days) while in 1996, Unit 2 was out of service for a 36 day planned refueling and maintenance outage. The amount of electricity delivered to the Company by the IPPs decreased by approximately 277 GWh or 2.0%. However, total IPP costs increased by approximately $18.0 million or 1.7%.

	1998		1997		1996		% Change from prior year 1998 to 1997		1997 to 1996	
(in millions of dollars)	GWh	Cost	GWh	Cost	GWh	Cost	GWh	Cost	GWh	Cost
Fuel for electric generation:										
Coal	7,988	$ 118.7	7,459	$ 106.4	7,095	$ 100.6	7.1%	11.6%	5.1%	5.8%
Oil	1,669	57.1	701	32.2	462	21.1	138.1	77.3	51.7	52.6
Natural gas	843	23.3	394	8.6	319	9.2	114.0	170.9	23.5	(6.5)
Nuclear	7,842	40.0	6,339	33.0	8,243	47.7	23.7	21.2	(23.1)	(30.8)
Hydro	2,694	—	2,905	—	3,679	—	(7.3)	—	(21.0)	—
	21,036	239.1	17,798	180.2	19,798	178.6	18.2	32.7	(10.1)	0.9
Electricity purchased:										
IPPs:										
Capacity	—	127.9	—	220.8	—	212.8	—	(42.1)	—	3.8
Energy and taxes	9,668	656.7	13,520	885.7	13,797	875.7	(28.5)	(25.9)	(2.0)	1.1
Total IPP purchases	9,668	784.6	13,520	1,106.5	13,797	1,088.5	(28.5)	(29.1)	(2.0)	1.7
Other	8,638	122.0	9,421	130.2	9,569	130.6	(8.3)	(6.3)	(1.5)	(0.3)
	18,306	906.6	22,941	1,236.7	23,366	1,219.1	(20.2)	(26.7)	(1.8)	1.4
Total generated and purchased	39,342	1,145.7	40,739	1,416.9	43,164	1,397.7	(3.4)	(19.1)	(5.6)	1.4
Fuel adjustment clause	—	96.3	—	(1.3)	—	(33.3)	—		—	
Losses/Company use	2,910	—	3,603	—	4,037	—	(19.2)	—	(10.8)	—
	36,432	$1,242.0	37,136	$1,415.6	39,127	$1,364.4	(1.9)%	(12.3)%	(5.1)%	3.8%

The above table presents the total costs for purchased electricity, while reflecting only fuel costs for Company generation. Other costs of power production, such as taxes, other operating expenses and depreciation are included within other income statement line items.

The Company's management of its IPP power supply generally divides the projects into three categories: hydroelectric, "must run" cogeneration and schedulable cogeneration projects.

There was lower snowfall during the winter months resulting in lower than normal 1998 spring run off. In addition, the January 1998 ice storm damaged several hydro generation stations. As a result, hydroelectric IPP projects delivered 56 GWh or 3.7% less under PPAs than they did for the same period last year, representing decreased payments to those IPPs of $1.7 million.

A substantial portion of the Company's portfolio of IPP projects has historically operated on a "must run" basis. This means that they would tend to run at maximum production levels regardless of the need for or economic value of the electricity produced. Output from "must run" cogeneration IPPs was 2,720 GWh or 33.7% lower than produced last year, mainly due to the closing of the MRA agreement, which terminated or restructured 13 of the largest contracts of this type. Separate from the MRA, the Company also bought out two IPP contracts with intermediate sized cogeneration facilities. See "Master Restructuring Agreement and the *PowerChoice* Agreement."

Quantities purchased from schedulable cogeneration IPPs also decreased 1,076 GWh or 27.5% and payments decreased $119.3 million. The decrease in payments is also mainly due to the closing of the MRA Agreement, which either terminated or amended all but one of these contract types. See "Master Restructuring Agreement and the *PowerChoice* Agreement."

Regulated gas revenues decreased by $91.7 million, or 14.0% in 1998, and decreased by $24.7 million, or 3.6%, in 1997. As shown in the table below, regulated gas revenues decreased in 1998 primarily due to decreased sales to ultimate customers as a result of the migration of commercial sales customers to the transportation class and due to warmer weather in the winter months. Regulated gas revenues were also negatively impacted by the regulated gas commodity cost adjustment clause ("CCAC"). See "Other Federal and State Regulatory Initiatives - Future of the Natural Gas Industry."

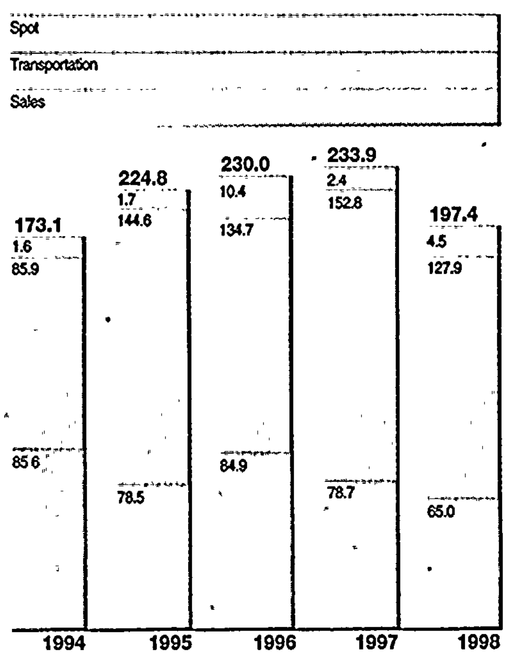
Regulated gas revenues decreased in 1997 primarily due to decreased sales to ultimate customers as a result of the migration of commercial sales customers to the transportation class, decreased spot market sales and a decrease in base rates of $5.9 million in accordance with the 1996 rate order. This was partially offset by higher regulated CCAC recoveries and an increase in revenues from the transportation of customer-owned gas.

Rates for transported gas (excluding aggregation services) yield lower margins than gas sold directly by the Company. Therefore, sales of gas transportation services have not had a proportionate impact on earnings, particularly in instances where customers that took direct service from the Company move to a transportation-only class. In addition, changes in CCAC revenues are generally margin- neutral.

	Increase (decrease) from prior year *(In millions of dollars)*		
Regulated Gas Revenues	**1998**	**1997**	**Total**
Base rates	$ —	$ (5.9)	$ (5.9)
Transportation of customer-owned gas	(1.6)	5.3	3.7
Purchased gas adjustment clause revenues	(38.5)	45.3	6.8
Spot market sales	2.4	(30.8)	(28.4)
Changes in volume and mix of sales to ultimate consumers	(54.0)	(38.6)	(92.6)
	$ (91.7)	$(24.7)	$(116.4)

Regulated gas sales, excluding transportation of customer-owned gas and spot market sales, were 65.0 million Dth in 1998, a 17.3% decrease from 1997. Regulated gas sales for 1997 decreased 7.3% from 1996. See Regulated Electric and Gas Statistics - "Regulated Gas Statistics." The decrease in 1998 was in all ultimate consumer classes, primarily due to the warmer weather. Regulated gas revenues were also negatively impacted by a decrease in transportation volumes of 24.9 million Dth or 16.3% to customers purchasing gas directly from producers mainly as a result of the termination and restatement of the PPAs as part of the MRA. The decreases were partially offset by increased spot market sales (sales for resale), which are generally from higher priced gas available to the Company and, therefore, yield margins that are substantially lower than traditional sales to ultimate customers.

TOTAL GAS DELIVERED (MILLIONS OF DEKATHERMS)



Changes in regulated gas revenues and Dth sales by customer group are detailed in the table below:

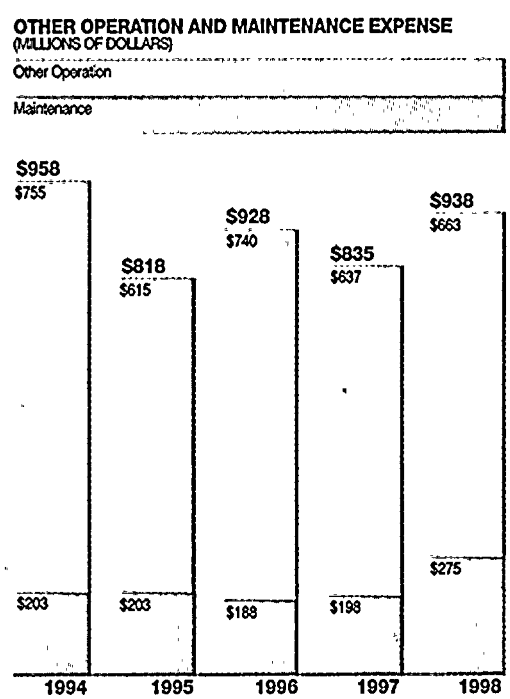
Class of service	1998 % of Gas Revenues	% Increase (decrease) from prior year 1998 Revenues	1998 Sales	1997 Revenues	1997 Sales
Residential	66.9%	(13.3)%	(14.4)%	4.5%	(2.7)%
Commercial	19.6	(25.4)	(22.9)	(8.7)	(13.0)
Industrial	0.6	(44.8)	(45.5)	(50.9)	(50.1)
Total to ultimate consumers	87.1	(16.7)	(17.3)	(0.3)	(7.3)
Other gas systems	—	(46.9)	(39.3)	(5.8)	(6.7)
Transportation of customer-owned gas	9.6	(2.8)	(16.3)	10.5	13.5
Spot market sales	1.5	37.9	83.6	(82.9)	(76.6)
Miscellaneous	1.8	155.7	—	263.1	—
Total	100.0%	(14.0)%	(15.6)%	(3.6)%	1.7%

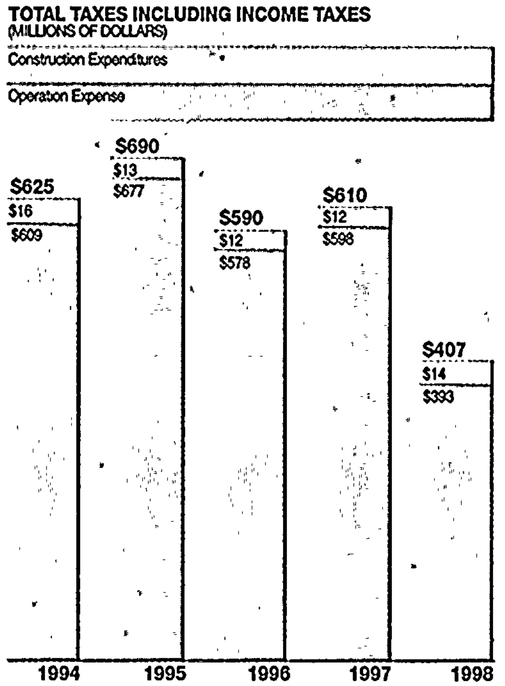
The total cost of gas purchased decreased 21.3% in 1998 and decreased 6.6% in 1997. The cost fluctuations generally correspond to sales volume changes, as well as a decrease in gas prices. The Company sold 4.5, 2.5 and 10.5 million Dth on the spot market in 1998, 1997 and 1996, respectively. The total cost of gas decreased $73.5 million in 1998. This was the result of a 19.3 million decrease in Dth purchased and withdrawn from storage for ultimate consumer sales ($71.7 million), a 1.3% decrease in the average cost per Dth purchased ($3.5 million) and a $1.0 million decrease in purchased gas costs and certain other items recognized and recovered through the CCAC. These decreases were partially offset by a $2.7 million increase in Dth purchased for spot market sales.

The total cost of gas decreased $24.4 million in 1997. This was the result of a 5.3 million decrease in Dth purchased and withdrawn from storage for ultimate consumer sales ($18.8 million) and a $22.5 million decrease in Dth purchased for spot market sales, partially offset by a 3.3% increase in the average cost per Dth purchased ($10.7 million) and a $6.3 million increase in purchased gas costs and certain other items recognized and recovered through the CCAC.

Through the electric FAC and gas CCAC, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. In the past, the Company's electric FAC provided for a partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. The Company absorbed losses of approximately $1.4 million and $13.1 million in 1996 and 1997, and $11.0 million for the first eight months in 1998, respectively. Effective September 1, 1998, under *PowerChoice*, the electric FAC has been eliminated. The Company does not believe that the elimination of the electric FAC will have a material adverse effect on its financial condition, as a result of its management of (1) power supplies provided through: (i) the operation of its own power plants, and future power purchase arrangements as part of the auction of the fossil and hydro assets; (ii) fixed price and quantity power purchases from NYPA and remaining IPPs; and (iii) fixed and indexed swap arrangements with IPP Parties; and (2) the transfer of the risk associated with electricity commodity prices to the customer through implementation of retail access included in the *PowerChoice* agreement.

Other operation and maintenance expense increased in 1998 by $102.5 million, or 12.3%, as compared to a decrease of $92.9 million or 10% in 1997. The increase in 1998 is primarily the result of costs associated in the 1998 storms (see "1998 Storms") and increased nuclear costs of $8 million mostly due to the extended Unit 2





refueling outage. Other operation and maintenance expense decreased in 1997 mainly due to lower bad debt expense. During 1996, the Company changed its method of assessing uncollectible customer accounts to give greater recognition to the increased risk of collecting past due customer bills which resulted in significantly higher bad debt expense recognition in 1996 as compared to 1997. Bad debt expense was $127.6 million, $46.5 million and $31.7 million in 1996, 1997 and 1998, respectively. Other operation and maintenance expense also decreased in 1997 as a result of a reduction in administrative and general expenses of $15.8 million, primarily due to a reduction in legal costs.

Other income increased by $17.6 million in 1998 and decreased by $10.9 million in 1997. Other income increased in 1998 mainly due to the deferral of MRA financing costs, which are reflected in interest charges, due to the delay in the implementation of *PowerChoice*. The increase was partially offset by lower interest income, which reflects the use of cash and also by lower subsidiary earnings.

Despite higher interest income ($12.0 million) related to increasing cash balances, other income was lower in 1997, since 1996 reflected a gain on the sale of a 50% interest in CNP ($15.0 million).

Interest charges increased in 1998 by $123.3 million after having remained fairly constant for the years 1996 and 1997. The increase in 1998 is mainly due to the interest charges incurred on the debt issued in connection with the MRA. Dividends on preferred stock decreased by $0.8 million and $0.9 million in 1998 and 1997, respectively, primarily due to a reduction in preferred stock outstanding through sinking fund redemptions. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.46% and 7.00%, respectively, in 1998 from 7.81% and 7.04%, respectively, in 1997.

Federal and foreign income taxes decreased by $193.3 million in 1998 primarily due to a decrease in pre-tax income and increased by $24.1 million in 1997 primarily due to an increase in pre-tax income. Other taxes decreased by $11.5 million in 1998 and decreased by $4.4 million in 1997. The 1998 decrease is mainly due to a reduction in GRT taxes of $17.6 million primarily due to the lower sales revenue for the year and due to the GRT credits received for customers in the Company's service territory that participate in New York State's Power for Jobs program. The 1997 decrease was primarily due to lower payroll taxes ($2.3 million) and lower sales taxes ($0.7 million).

Effects of Changing Prices

The Company is especially sensitive to inflation because of the amount of capital it typically needs and because its prices are regulated using a rate base methodology that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different than now. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its utility assets for the historical cost value at which they are recorded on the Company's books. In addition, the Company would not replace these with identical assets due to technological advances and competitive and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the cost of providing service if new facilities were installed. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

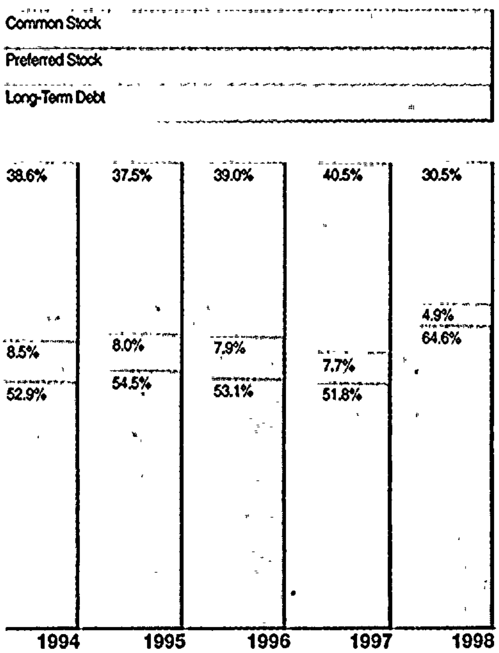
Financial Position, Liquidity and Capital Resources

Financial Position. The Company's capital structure at December 31, 1998 and 1997 was as follows:

%	1998	1997
Long-term debt	64.6	51.8
Preferred stock	4.9	7.7
Common equity	30.5	40.5

The closing of the MRA has significantly increased the leverage of the Company. Under the MRA, the Company paid an aggregate of $3.934 billion in cash, of which $3.212 billion was obtained through a public market offering of senior unsecured debt, $303.7 million from the public sale of 22.4 million shares of common stock, and the remainder from cash on hand. In addition, the Company issued 20.5 million shares of common stock to the IPP Parties. Through the anticipated increased operating cash flow resulting from the MRA and *PowerChoice* agreement and the sale of the generation assets, the planned rapid repayment of debt should deleverage the Company over time. Book value of the common stock was $16.92 per share at December 31, 1998, as compared to $18.89 per share at December 31, 1997. With the issuance of common stock at below book value to the IPP Parties as part of the MRA and the one-time non-cash write-off associated with the portion of the MRA regulatory asset disallowed in rates by the PSC, book value per share and earnings per share have been diluted.

CAPITALIZATION RATIOS

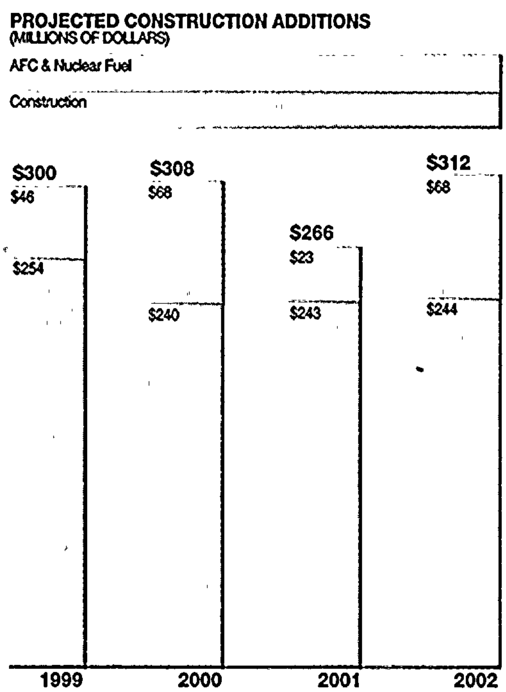


The 1998 ratio of earnings to fixed charges was 0.57 times. The ratios of earnings to fixed charges for 1997 and 1996 were 2.02 times and 1.57 times, respectively. The change in the ratio is primarily due to the consummation of the MRA, since the MRA and *PowerChoice* agreements will have the effect of substantially depressing earnings during its five-year term, while at the same time substantially improving operating cash flows. The primary result of the MRA was to convert a large and growing off-balance sheet payment obligation that threatened the financial viability of the Company into a fixed and more manageable capital obligation.

The Company's EBITDA for 1998 was approximately $990.5 million. After the changes from *PowerChoice* and the MRA are fully reflected in a consecutive 12-month period, EBITDA is expected to increase to approximately $1.2 billion to $1.3 billion per year. EBITDA represents earnings before interest charges, interest income, income taxes, depreciation and amortization, amortization of nuclear fuel, allowance for funds used during construction, non-cash regulatory deferrals and other amortizations and extraordinary items. The ratio of EBITDA to net cash interest for 1998 was 2.9 times. Net cash interest is defined as interest charges plus allowance for funds used during construction less the non-cash impact of the net amortization of discount on long-term debt and interest accrued on the Nuclear Waste Policy Act liability less interest income. The ratio of EBITDA to net cash interest is also expected to improve as the results of the MRA and *PowerChoice* are fully reflected in a consecutive 12-month period and the Company reduces its debt. EBITDA is a non-GAAP measure of cash flows and is presented to provide additional information about the Company's ability to meet its future requirements for debt service. EBITDA should not be considered an alternative to net income as an indicator of operating performance or as an alternative to cash flows, as presented on the Consolidated Statement of Cash Flows, as a measure of liquidity.

Common Stock Dividend. The Board of Directors omitted the common stock dividend beginning the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addressed growing pressure from mandated power purchases and weaker sales and is the primary reason for the increase in the cash balance. In making future dividend decisions, the Board of Directors will evaluate, along with standard business considerations, the financial condition of the Company, limitations on dividend payments under the *PowerChoice* agreement, limitations on common stock dividends in indenture agreements, the degree of competitive pressure on its prices, the level of available cash flow and retained earnings and other strategic considerations. The Company expects to dedicate a substantial portion of its future expected positive cash flow to reduce the leverage created in connection with the implementation of the MRA. The *PowerChoice* agreement establishes limits to the annual amount of common stock dividends that can be paid by the regulated business. The *PowerChoice* agreement limits the amount of common stock dividends that can be paid by the regulated company to the holding company, but does not limit the dividends the holding company may pay to its shareholders. The limit under *PowerChoice* is based upon the amount of net income each year of the regulated company, plus a specified amount ranging from $50 million in 1998 to $100 million in 2000 and declining thereafter through 2007. The limitation excludes one-time dividends associated with asset sales. The dividend limitation is subject to review after the term of the *PowerChoice* agreement. Furthermore, the Company forecasts that earnings for the five-year term of the *PowerChoice* agreement will be substantially depressed, as non-cash amortization of the MRA regulatory asset is occurring and the interest costs on the IPP debt is the greatest. See " Master Restructuring Agreement and the *PowerChoice* Agreement."

Construction and Other Capital Requirements. The Company's total capital requirements consist of amounts for the Company's construction program (see Note 9. "Commitments and Contingencies - Construction Program,"), nuclear decommissioning funding requirements (See Note 3. Nuclear Operations - "Nuclear Plant Decommissioning"), working capital needs, maturing debt issues and sinking fund provisions on preferred stock. Annual expenditures for the years 1996 to 1998 for construction and nuclear fuel, including related AFC and overheads capitalized, were $352.1 million, $290.8 million and $351.2 million, respectively, and are budgeted to be approximately $300 million for 1999 and to range from $266 - $312 million for each of the subsequent three years. Capital expenditures for 1998 increased primarily due to the costs incurred to rebuild a portion of the Company's regulated electric transmission and distribution facilities as a result of several storms in 1998 (see "1998 Storms"). The estimate for 1999 and beyond excludes construction expenditures relating to the fossil and hydro generation assets.



Mandatory debt and preferred stock retirements are expected to add approximately another $320 million to the 1999 estimate of capital requirements. In addition, the Company is obligated to reduce the Senior Debt outstanding by using 85% of the net proceeds of the sale of the generation assets within 180 days after the receipt of such proceeds. As of December 31, 1998, the Company has entered into agreements for the sale of its hydroelectric and coal-fired generation assets for $780 million. It is anticipated that transaction closings will occur in mid-1999 after receipt of the necessary regulatory approvals. The Company is also pursuing the sale of its oil and gas-fired, and nuclear generation assets. The Company may also use the positive cash flow generated as a result of the MRA and the cash tax benefits received as a result of the tax net operating loss generated from the MRA to further reduce debt. The estimate of construction additions included in capital requirements for the period 1999 to 2003 will be reviewed by management to give effect to the overall objective of further reducing construction spending where possible. See discussion in "Liquidity and Capital Resources" section below, which describes how management intends to meet its financing needs for the five-year period, 1999 to 2003.

Liquidity and Capital Resources. External financing plans are subject to periodic revision as underlying assumptions are changed to reflect developments and market conditions. The ultimate level of financing during the period 1999 through 2003 will be affected by, among other things: the cash tax benefits anticipated because the MRA generated a net tax operating loss carry forward in 1998; the implementation of the *PowerChoice* agreement, levels of common dividend payments, if any, and preferred dividend payments; the results of the sales of the Company's generation assets; the Company's competitive position and the extent to which competition penetrates the Company's markets; potential future actions with respect to IPPs not covered under the MRA; and uncertain energy demand due to the weather and economic conditions. The proceeds of the sales of the generation assets will be subject to the terms of the Company's mortgage indenture and the note indenture that was entered into in connection with the MRA debt financing. The Company could also be affected by the outcome of the NRC's consideration of new rules for adequate financial assurance of nuclear decommissioning obligations. (See "NRC Policy Statement and Amended Decommissioning Funding Regulations"). The Company does not anticipate the need to incur any additional financing in 1999 and expects that all capital needs can be met internally. However, the Company may refinance existing debt to take advantage of lower interest rates.

The Company has an $804 million senior bank financing with a bank group, consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA. The interest rate applicable to the senior bank financing is variable based on certain rate options available under the agreement and currently approximates 6.5% (but is capped at 15%). As of December 31, 1998, the amount outstanding under the senior bank financing was $529 million, consisting of $105 million under the term loan facility and $424 million of letters of credit, leaving the Company with $275 million of borrowing capability under the financing. The Company amended the financing as of June 30, 1998. The amendment, which included an extension of the term from June 30, 1999 to June 1, 2000, also accommodates the holding company structure and permits the auction of fossil and hydro generating assets.

This facility is collateralized by first mortgage bonds, which were issued on the basis of additional property under the earnings test required under the mortgage trust indenture ("First Mortgage Bonds"). The Company has the ability to issue First Mortgage Bonds to the extent that there have been redemptions since June 30, 1998. The Company redeemed $60 million First Mortgage Bonds in August 1998.

During November 1998, the Company refinanced its 8 7/8 percent series of tax-exempt bonds issued through NYSERDA. The $75 million bonds were refinanced at 5.15%. The refinancing will reduce interest expense by approximately $2.8 million per year, not including the costs of issuance.

The Company believes that the closing of the MRA and implementation of *PowerChoice* will result in substantially depressed earnings during its five-year term, but will substantially improve operating cash flows. There is risk that credit ratings could decline or not increase if the current expectation of stranded cost recovery is endangered.

In December 1998, the Company received a ruling from the IRS to the effect that the amount of cash and the value of common stock that was paid to the terminated IPP Parties will be currently deductible and generate a substantial net operating loss ("NOL") for federal income tax purposes, such that the Company will not pay taxes for 1998. Further, the Company has carried back unused NOL to the years ended 1996 and 1997, and also for the years 1988 through 1990, which has resulted in tax refunds of $130 million and $5 million, respectively, received in January 1999. In addition, the Company anticipates that it will be able to utilize the remaining $3.3 billion NOL deductions carried over to future years before the expiration date in 2019. The Company's ability to utilize the NOL generated as a result of the MRA could be limited under the rules of section 382 of the Internal Revenue Code if certain changes in the Company's common stock ownership were to occur in the future. In general, the limitation is triggered by a more than 50% change in stock ownership during a three-year testing period by shareholders that own, directly or indirectly, 5% or more of the common stock. For purposes of making the change in ownership computation, the IPP Parties who were issued common stock pursuant to the MRA are likely to be considered a separate 5% shareholder group, as will the purchasers of common stock in the public offering completed immediately prior to consummation of the MRA. Under the computational rules prescribed by applicable Treasury regulations, the aggregate increase in stock ownership experienced by these shareholder groups as a result of their participation in the public offering and the MRA was likely no greater than 17%. Thus, if the IPP Parties, the purchasers in the public offering, and any other 5% shareholders collectively experience ownership increases totaling more than 33% during any three year testing period that includes the consummation dates of the public offering and the MRA, the statutory threshold could be breached and the NOL limitation would in that event apply. The rules for determining change in stock ownership for purposes of Code Section 382 are extremely complicated and in many respects uncertain. A stock ownership change could occur as a result of circumstances that are not within the control of the Company. If a more than 50% change in ownership were to occur, the Company's remaining usable NOL likely would be significantly lower in the future than the NOL amount which otherwise would be usable absent the limitation. Consequently, the Company's net cash position could be significantly lower as a result of tax liabilities, which otherwise would be eliminated or reduced through unrestricted use of the NOL.

During 1995, past due accounts receivable increased significantly. A number of factors contributed to the increase, including rising prices (particularly to residential customers). Rising prices have been driven by increased payments to IPPs and high taxes and have been passed on in customers' bills. The stagnant economy in the Company's service territory since the early 1990's has adversely affected collection of past-due accounts. Also, laws, regulations and regulatory policies impose more stringent collection limitations on the Company than those imposed on business in general; for example, the Company faces more stringent requirements to terminate service during the winter heating season. In 1996, the Company increased its allowance for doubtful accounts because of its reassessment of the collection risk associated with residential accounts receivable and arrears. Over the last several years, the Company has implemented a number of collection initiatives that have resulted in lower arrears levels, and in 1998, the Company lowered its allowance for doubtful accounts.

The information gathered in developing these strategies enabled management to update its risk assessment of the accounts receivable portfolio. Based on this assessment, management determined in 1996 that the level of risk associated primarily with the older accounts had increased and the historical loss experience no longer applied. Accordingly, the Company determined that a significant portion of the past-due accounts receivable (principally of residential customers) might be uncollectible, and wrote-off a substantial number of these accounts as well as increased its allowance for doubtful accounts in 1996 and 1997. In 1998, 1997 and 1996, the Company charged $31.7 million, $46.5 million and $127.6 million, respectively to bad debt expense. The allowance for doubtful accounts is based on assumptions and judgments as to the effectiveness of collection efforts. Future results with respect to collecting the past-due receivables may prove to be different from those anticipated. Although the Company has experienced improvement in collection efforts, future results are necessarily dependent upon the following factors, including, among other things, the effectiveness of the strategies implemented to date, the support of regulators and legislators to allow utilities to move towards commercial collection practices and improvement in the condition of the economy in the Company's service territory. The introduction of competition requires that policies and practices that were central to traditional regulation, including those involving collections, be changed so as not to jeopardize the benefits of competition to customers but not increase collection risk to the Company. The Company is actively pursuing these issues before the PSC.

Net cash used in operating activities increased $3,778.0 million in 1998 primarily due to the consummation of the MRA.

Net cash used in investing activities increased $53.1 million in 1998 primarily as a result of an increase in the acquisition of utility plant of $98.1 million, mainly due to the January 1998 ice storm and the September 1998 windstorm.

Net cash provided by financing activities increased $3,573.1 million, primarily due to the issuance of the senior notes and public sale of common stock used to consummate the MRA.

Quantitive and Qualitive Disclosures about Market Risk

The financial instruments held or issued by the regulated business are for purposes other than trading. The Company's energy marketing subsidiary engages in both trading and non-trading activities.

Quantitative and qualitative disclosures are discussed by market risk exposure category:

- Interest Rate Risk
- Commodity Price Risk
- Equity Price Risk
- Foreign Currency Exchange Risk

The Company has a foreign currency exchange risk as a result of its investments in Canada through its subsidiary Opinac Energy Corporation. Translation adjustments due to exchange rate movement across the value of the subsidiary is reported in Capitalization as a Foreign Currency Translation Adjustment (see "Note 5. - Capitalization") and is a component of Comprehensive Income. See "Consolidated Statements of Comprehensive Income." In aggregate, the risk of loss does not pose a material threat to the Company's consolidated results of operations or total capitalization.

The Company maintains a Financial Risk Management Policy Manual (the "Policy") applicable to the regulated company that outlines the parameters within which corporate managers are to engage in, manage, and report on various areas of risk exposure. At the core of the Policy is a condition that the Company will engage in activities at risk, only to the extent that those activities fall within commodities and financial markets to which it has a physical market exposure, in terms and in volumes consistent with its core business. That core business is to supply energy, in the form of electricity and natural gas to customers within the Company's service territory. The policies of the Company may be revised as its primary markets continue to change, principally as increased competition is introduced and the role of the Company in these markets evolves.

The Company's energy marketing subsidiary maintains a separate Risk Management and Trading Policy Manual that allows for transactions such as marketing and trading in retail and wholesale, physically and financially settled, energy based instruments. These actions expose this subsidiary to a number of risks such as forward price, deliverability, market liquidity and credit risk. Like the Company's Policy, the energy trading policy seeks to assure that risks are identified, evaluated and actively managed.

Interest Rate Risk. The Company's exposure to changes in interest rates is due to its financing through a senior debt facility, several series of adjustable rate promissory notes and adjustable rate preferred stock. See "Note 5. Capitalization" and "Note 6. Bank Credit Arrangements." Under the senior debt facility, the Company currently has an outstanding term loan of $105 million. The adjustable rate promissory notes are currently valued at $413.8 million, and the Company has $122.5 million outstanding in adjustable rate preferred stock. There is no interest rate cap on the promissory notes. The interest on the term loan is variable but capped at 15%.

Dividend rates for the preferred stock are indexed to U.S. government interest bearing securities plus or minus an amount stipulated in each series and have floors of 6.5% to 7.0% and caps of between 13.5% and 16.5%. As of December 31, 1998, the rate calculated on the index for each series is below the floor; therefore, the current rate is equal to the floor. Future changes in the indexed rate will not result in an exposure to higher dividend rates until the floor is exceeded. However, for the purposes of the following sensitivity analysis, a hypothetical one percent increase from the floor dividend rate is assumed.

The Company also maintains long term debt at fixed interest rates. A controlling factor on the exposure to interest rate variations is the mix of fixed to variable rate instruments maintained by the Company. All adjustable rate instruments comprise 6.4% of total capitalization. The term loan and promissory notes are 7.7% of total long-term debt, thus limiting Company exposure to interest rate fluctuations.

If interest rates averaged one percent more in 1999 versus 1998, the Company's interest expense would increase and income before taxes decrease by approximately $5.2 million. This figure was derived by applying the hypothetical one percent variance across the variable rate debt of $518.8 million at December 31, 1998 (the sum of the term loan and promissory notes). The same one percent increase in the preferred dividend rate applied against the outstanding balance of $122.5 million would result in an increase to dividend payments of $1.2 million, assuming that the indexed rate was between the floor and cap. Under *PowerChoice*, prices to customers are fixed for three years, with limited increases available in years four and five, if justified by the Company. Changes in the actual cost of capital from levels assumed in *PowerChoice* would create either exposure or opportunity for the Company until reflected in future prices.

Commodity Price Risk. The Company is exposed to market fluctuations in the prices for electricity, natural gas, coal, and oil. The Company, exclusive of its energy marketing subsidiary, does not, generally, speculate on movements in the underlying prices for these commodities. Purchases are based on analysis performed in relation to fuel needs for power generation and customer delivery for electricity and natural gas. Where possible, the Company takes positions in order to mitigate expected price increases but only to the extent that quantities are based on expectations of delivery. The Company attempts to mitigate exposure through a program that hedges risks as appropriate.

Niagara Mohawk Energy, Inc., a wholly owned subsidiary of the Company, does engage in both trading and non-trading activities.

Transactions entered into for trading purposes are accounted for on a mark-to-market basis with changes in fair value recognized as a gain or loss in the period of change. At December 31, 1998, there were no open trading positions.

Activities for non-trading purposes generally consist of transactions entered into to hedge the market fluctuations of contractual and anticipated commitments. Gas futures are used for hedging purposes. Changes in market value of futures contracts relating to hedged items are deferred until the physical transaction occurs, at which time, income or loss is recognized. The fair value of open positions for non-trading purposes at December 31, 1998, as well as the effect of these activities on the Company's results of operations for the same period ending, was not material.

The fair values of futures and forward contracts are determined using quoted market prices or broker's quotes.

The commodity risk exposure of Niagara Mohawk Energy, Inc. does not constitute a material risk of loss to the Company.

The regulated company, as part of the MRA, entered into restated indexed swap contracts with eight IPPs. See Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the *PowerChoice* Agreement" for a more detailed discussion of the indexed swap contracts.

The fair value of the liability under the indexed swap contracts, based upon the difference between projected future market prices and indexed contract prices applied to the notional quantities and discounted at 8.5% is approximately $693 million and is recorded on the balance sheet as a liability for indexed swap contracts. The discount rate is based upon comparable debt instruments of the Company. Based upon the PSC's approval of the restated contracts, including the indexed swap contracts, as part of the MRA and being provided a reasonable opportunity to recover the estimated indexed swap liability from customers, the Company has recorded a corresponding regulatory asset. The amount of the recorded liability and regulatory asset is sensitive to changes in discount rate, anticipated future market prices and changes in the indices upon which the indexed swap contracts are based. However, changes in anticipated future market prices and discount rates will not impact the future cash flow of the Company when considering the all-in price of the notional quantities of energy. Specifically, as market prices rise or fall, payments under the indexed swap contracts move inversely. Similarly, changes in discount rates will not impact the all-in price. If the indexed contract price were to increase or decrease by one percent, the Company would see a $15.5 million increase or decrease in the present value of the projected over-market exposure. If the market prices were to increase or fall by one percent, the Company would see a $7.5 million decrease or increase in the projected over-market exposure. If the discount rate were to increase or decrease to 9.0% or

8.0%, the net present value of the projected over market exposure would decrease or increase by approximately $10.5 million.

Under *PowerChoice*, the Company agreed to divest of its fossil generation assets through an auction process. As of December 31, 1998, the Company has reached an agreement to sell its coal-fired generation plants with an anticipated close in mid-1999. The Company continues to pursue the sale of its two oil and gas-fired generation plants. Central Hudson Gas and Electric Corporation has indicated that the sale of the Company's share of the Roseton Steam Station is not expected to close until mid-2000. The terms of these sales call for the new owners to take possession of the existing fuel inventory at book value. Because of these anticipated sales and the level of coal and oil inventory on hand at December 31, 1998, the Company will not be exposed to any significant commodity price risks for fuel used in generation in 1999 and beyond.

The Company has an exposure to market price fluctuations for the cost of the natural gas sold to customers. The gas prices are most volatile in the winter months. The Company has adopted a policy to reduce the variability in gas costs, primarily over the winter months. The Company has accomplished this by limiting or eliminating gas price volatility on four contracts and through the use of stored gas supplies where the price is already fixed. These two factors, as compared to the winter gas needs, allow the Company to reduce or eliminate volatility on approximately 49% of anticipated demand.

The remaining gas needs of the Company are met through spot market purchases and are subject to market price fluctuations. However, the Company has a gas commodity cost adjustment clause (CCAC) built into its approved rate structure that limits this risk. This pricing mechanism calls for a 50/50 sharing, between customers and stockholders, of the variability between a target price for gas and actual purchases up to $2.25 million annually. Variability greater than $2.25 million accrues to or is borne by the customers.

Equity Price Risk. The NRC requires nuclear plant owners to place funds in an external trust to provide for the cost of decommissioning of the contaminated portions of nuclear facilities. See Note 3. - "Nuclear Operations." The Company has established qualified and non-qualified trust funds for Unit 1 and Unit 2. As of December 31, 1998, these funds were invested in fixed income securities, domestic equity securities, and cash equivalents. The fixed income securities are subject to interest rate fluctuations and the equity securities to price change in the equity markets. The funds asset allocation is designed to maximize returns commensurate with the Company's risk tolerance.

The Company's investment policy for managing the nuclear decommissioning trust funds conforms to NRC guidelines. The policy's main objective is to assure that the growth in the decommissioning funds, together with Company contributions, will ultimately provide sufficient funds to decommission Units 1 and 2. This objective is met by optimizing the return; maintaining a diversified portfolio; and seeking a return competitive with like institutions employing similar strategies.

Report of Management

Niagara Mohawk

The consolidated financial statements of the Company and its subsidiaries were prepared by and are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Corporate Policy Register and a Code of Business Conduct (the "Code") that supply employees with a framework describing and defining the Company's overall approach to business and require all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by PricewaterhouseCoopers LLP, the Company's independent accountants, in accordance with GAAP. In planning and performing its audit, Pricewaterhouse-Coopers LLP considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report. The Audit Committee of the Board of Directors, consisting of five outside directors who are not employees, meets regularly with management, internal auditors and PricewaterhouseCoopers LLP to review and discuss internal accounting controls, audit examinations and financial reporting matters. Pricewaterhouse-Coopers LLP and the Company's internal auditors have free access to meet individually with the Audit Committee at any time, without management being present.

William E. Davis

William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

Report of Independent Accountants

PRICEWATERHOUSECOOPERS

To the Stockholders and
Board of Directors of
Niagara Mohawk Power Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings, of cash flows and of comprehensive income present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. 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 generally accepted auditing standards, 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.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Syracuse, New York

January 28, 1999

Consolidated Balance Sheets

At December 31,	1998	1997
	In thousands of dollars	
ASSETS		
Utility plant *(Note 1)*:		
Electric plant	$ 8,826,650	$ 8,752,865
Nuclear fuel	604,213	577,409
Gas plant	1,179,716	1,131,541
Common plant	349,066	319,409
Construction work in progress	471,802	294,650
Total utility plant	11,431,447	11,075,874
Less: Accumulated depreciation and amortization	4,553,488	4,207,830
Net utility plant	6,877,959	6,868,044
Other property and investments	411,106	371,709
Current assets:		
Cash, including temporary cash investments of $122,837 and $315,708, respectively	172,998	378,232
Accounts receivable (less allowance for doubtful accounts of $47,900 and $62,500, respectively) *(Notes 1 and 9)*	427,588	492,244
Materials and supplies, at average cost:		
Coal and oil for production of electricity	42,299	27,642
Gas storage	38,803	39,447
Other	118,855	118,308
Refundable Federal income taxes	130,411	—
Prepaid taxes	17,282	15,518
Other	22,208	20,309
	970,444	1,091,700
Regulatory assets *(Note 2)*:		
MRA regulatory asset	4,045,647	7,516
Indexed swap contracts regulatory asset	535,000	—
Regulatory tax asset	425,898	399,119
Deferred finance charges	—	239,880
Deferred environmental restoration costs *(Note 9)*	220,000	220,000
Unamortized debt expense	51,922	57,312
Postretirement benefits other than pensions	52,701	56,464
Other	137,061	196,533
	5,468,229	1,176,824
Other assets	133,449	75,864
	$13,861,187	$ 9,584,141

The accompanying notes are an integral part of these financial statements

Consolidated Balance Sheets

At December 31,	1998	1997
	In thousands of dollars	
CAPITALIZATION AND LIABILITIES		
Capitalization *(Note 5)*:		
Common stockholders' equity:		
Common stock, issued 187,364,863 and 144,419,351, respectively	$ 187,365	$ 144,419
Capital stock premium and expense	2,358,380	1,794,739
Accumulated other comprehensive income	(21,643)	(15,051)
Retained earnings	646,040	803,420
	3,170,142	2,727,527
Non-redeemable preferred stock	440,000	440,000
Mandatorily redeemable preferred stock	68,990	76,610
Long-term debt	6,417,225	3,417,381
Total capitalization	10,096,357	6,661,518
Current liabilities:		
Long-term debt due within one year *(Note 5)*	312,240	67,095
Sinking fund requirements on redeemable preferred stock *(Note 5)*	7,620	10,120
Accounts payable	197,124	263,095
Payable on outstanding bank checks	39,306	23,720
Customers' deposits	17,148	18,372
Accrued taxes	6,254	9,005
Accrued interest	132,236	62,643
Accrued vacation pay	38,727	36,532
Other	91,877	64,756
	842,532	555,338
Regulatory and other liabilities *(Note 2)*:		
Deferred finance charges	—	239,880
Accumulated deferred income taxes *(Notes 1 and 7)*	1,511,417	1,387,032
Employee pension and other benefits *(Note 8)*	235,376	240,211
Unbilled revenues *(Note 1)*	30,652	43,281
Liability for indexed swap contracts *(Note 10)*	693,363	—
Other	231,490	236,881
	2,702,298	2,147,285
Commitments and contingencies *(Notes 2 and 9)*:		
Liability for environmental restoration	220,000	220,000
	$13,861,187	$9,584,141

The accompanying notes are an integral part of these financial statements

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	1998	1997	1996
	In thousands of dollars		
Operating revenues:			
Electric	$3,261,144	$ 3,309,441	$ 3,308,979
Gas	565,229	656,963	681,674
	3,826,373	3,966,404	3,990,653
Operating expenses:			
Fuel for electric generation	239,982	179,455	181,486
Electricity purchased	1,001,991	1,236,108	1,182,892
Gas purchased	272,141	345,610	370,040
Other operation and maintenance expenses	937,798	835,282	928,224
PowerChoice charge *(Note 2)*	263,227	—	—
Amortization of the MRA regulatory asset	128,833	—	—
Depreciation and amortization *(Note 1)*	355,417	339,641	329,827
Other taxes	459,961	471,469	475,846
	3,659,350	3,407,565	3,468,315
Operating income	167,023	558,839	522,338
Other income (deductions) *(Note 1)*	42,602	24,997	35,943
Income before interest charges	209,625	583,836	558,281
Interest charges *(Note 1)*	397,178	273,906	278,033
Income (loss) before federal and foreign income taxes	(187,553)	309,930	280,248
Federal and foreign income taxes *(Note 7)*	(66,728)	126,595	102,494
Income (loss) before extraordinary item	(120,825)	183,335	177,754
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes of $36,273 *(Note 2)*	—	—	(67,364)
Net income (loss)	(120,825)	183,335	110,390
Dividends on preferred stock	36,555	37,397	38,281
Balance available for common stock	(157,380)	145,938	72,109
Retained earnings at beginning of year	803,420	657,482	585,373
Retained earnings at end of year	$ 646,040	$ 803,420	$ 657,482
Average number of shares of common stock outstanding *(in thousands)*	166,186	144,404	144,350
Basic and diluted earnings (loss) per average share of common stock before extraordinary item	$ (0.95)	$ 1.01	$ 0.97
Extraordinary item	—	—	(0.47)
Basic and diluted earnings per average share of common stock	$ (0.95)	$ 1.01	$ 0.50

Consolidated Statements of Comprehensive Income

For the year ended December 31,	1998	1997	1996
	In thousands of dollars		
Net income (loss)	$ (120,825)	$ 183,335	$ 110,390
Other comprehensive income (loss):			
Unrealized gains (losses) on securities, net of tax	304	6	(231)
Foreign currency translation adjustment	(6,896)	(4,567)	(708)
Other comprehensive income (loss):	(6,592)	(4,561)	(939)
Comprehensive income (loss):	$ (127,417)	$ 178,774	$ 109,451

( ) Denotes deduction

The accompanying notes are an integral part of these financial statements

Consolidated Statements of Cash Flows *Increase (Decrease) in Cash*

For the year ended December 31,	1998	1997	1996
	In thousands of dollars		
Cash flows from operating activities:			
Net income (loss)	$ (120,825)	$ 183,335	$ 110,390
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
PowerChoice charge	263,227	—	—
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes	—	—	67,364
Depreciation and amortization	355,417	339,641	329,827
Amortization of MRA regulatory asset	128,833	—	—
Amortization of nuclear fuel	30,798	25,241	38,077
Provision for deferred income taxes	97,606	46,994	(6,870)
Gain on sale of subsidiary	—	—	(15,025)
Unbilled revenues	(12,629)	(6,600)	21,471
Net accounts receivable	64,656	(118,939)	121,198
Materials and supplies	(14,341)	(1,306)	2,265
Accounts payable and accrued expenses	(38,712)	(11,175)	8,224
Accrued interest and taxes	66,842	4,180	(11,750)
MRA regulatory asset	(3,959,508)	(7,516)	—
Refundable Federal income taxes	(130,411)	—	—
Changes in other assets and liabilities	28,592	83,720	35,231
Net cash provided by (used in) operating activities	(3,240,455)	537,575	700,402
Cash flows from investing activities:			
Construction additions	(365,396)	(286,389)	(296,689)
Nuclear fuel	(26,804)	(4,368)	(55,360)
Less: Allowance for other funds used during construction	8,626	5,310	3,665
Acquisition of utility plant	(383,574)	(285,447)	(348,384)
Materials and supplies related to construction	(219)	1,042	8,362
Accounts payable and accrued expenses related to construction	(9,678)	(2,794)	2,056
Other investments	(35,069)	(115,533)	541
Proceeds from sale of subsidiary (net of cash sold)	—	—	14,600
Other	(18,551)	8,761	(8,786)
Net cash used in investing activities	(447,091)	(393,971)	(331,611)
Cash flows from financing activities:			
Issuance of common stock	316,389	—	—
Proceeds from long-term debt	3,361,178	—	105,000
Reductions of preferred stock	(10,120)	(8,870)	(10,400)
Reductions of long-term debt	(135,000)	(44,600)	(244,341)
Dividends paid	(36,555)	(37,397)	(38,281)
Other	(13,580)	97	(8,846)
Net cash provided by (used in) financing activities	3,482,312	(90,770)	(196,868)
Net increase (decrease) in cash	(205,234)	52,834	171,923
Cash at beginning of year	378,232	325,398	153,475
Cash at end of year	$ 172,998	$ 378,232	$ 325,398
Supplemental disclosures of cash flow information:			
Interest paid	$ 315,541	$279,957	$286,497
Income taxes paid (refunded)	$ (12,127)	$ 82,331	$ 95,632

Supplemental schedule of noncash financing activities:

Issued 20,546,264 shares of common stock, valued at $14.75 per share to the IPP Parties on June 30, 1998 or $303.1 million

The accompanying notes are an integral part of these financial statements

NOTE 1. Summary of Significant Accounting Policies

The Company is subject to regulation by the PSC and FERC with respect to its rates for service under a methodology, which establishes prices, based on the Company's cost. The Company's accounting policies conform to GAAP, including the accounting principles for rate-regulated entities with respect to the Company's nuclear, transmission, distribution and gas operations (regulated business), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The Company discontinued the application of regulatory accounting principles to its fossil and hydro generation operations in 1996 (see Note 2). In order to be in conformity with GAAP, management is required to use estimates in the preparation of the Company's financial statements.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly owned subsidiaries. Inter-company balances and transactions have been eliminated.

Utility Plant: The cost of additions to utility plant and replacements of retirement units of property are capitalized. Cost includes direct material, labor, overhead and AFC. Replacement of minor items of utility plant and the cost of current repairs and maintenance are charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. The discontinuation of SFAS No. 71 to the fossil and hydro operations did not affect the carrying value of the Company's utility plant.

Allowance for Funds Used During Construction: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction for its regulated business. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect during 1998 was 9.19%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the "Interest charges" and "Other income" sections, respectively, of the Consolidated Statements of Income. The amount of AFC credits recorded in each of the three years ended December 31, in thousands of dollars, was as follows:

	1998	1997	1996
Other income	$ 8,626	$5,310	$3,665
Interest charges	10,228	4,396	3,690

As a result of the discontinued application of SFAS No. 71 to the fossil and hydro operations, the Company capitalizes interest cost associated with the construction of fossil and hydro assets.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the license lives for nuclear and hydro classes of depreciable property and the average service lives for all other classes. The percentage relationship between the total provision for depreciation and average depreciable property was approximately 3.4% to 3.5% for the years 1996 through 1998. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Unit 1 and its share of Unit 2 are being accrued over the service lives of the units, recovered in rates through an annual allowance and currently charged to operations through depreciation. The Company expects to commence decommissioning of both units shortly after cessation of operations at Unit 2 (currently planned for 2026), using a method which removes or decontaminates the Units' components promptly at that time. See Note 3. - "Nuclear Plant Decommissioning."

The Company currently recognizes the liability for nuclear decommissioning over the service life of the plant as an increase to accumulated depreciation and does not recognize the closure or removal obligation associated with its fossil and hydro plants. The Company's *PowerChoice* agreement provides for the recovery of nuclear decommissioning costs. As discussed in Note 2, the Company is in the process of selling its fossil and hydro generating assets through an auction process. In addition, the Company has announced plans to pursue the sale of its nuclear assets (see Note 3).

Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per KWh of net generation available for sale, is based upon a contract with the DOE. These costs are charged to operating expense.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly. The Company accrues the estimated revenue associated with energy consumed and not billed at the end of the fiscal period. The unbilled revenues included in accounts receivable at December 31, 1998 and 1997 were $205.6 million and $211.9 million, respectively.

In accordance with regulatory practice, accrued unbilled revenues are not recognized in results of operations until authorized and may be used to reduce future revenue requirements. Such amounts are included in "Other Liabilities" pending regulatory disposition. Under the *PowerChoice* agreement, $8.6 million of unrecognized unbilled electric revenues as of the implementation date of *PowerChoice* were netted with certain other regulatory assets and liabilities and subsequent changes in the estimated unbilled electric revenues are recognized currently in results of operations. At December 31, 1998 and 1997, $30.7 million and $34.7 million, respectively, of unbilled gas revenues remain unrecognized in results of operations.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost variances in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed purchased gas costs included in approved rate schedules. As a result of such periodic changes; a portion of purchased gas costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the gas adjustment clause. However, the Company has been permitted to defer and bill or credit such portions to customers, through the gas adjustment clause, over a specified period of time from the effective date of each change. Under the *PowerChoice* agreement, the electric fuel adjustment clause was discontinued as of September 1, 1998.

In December 1996, the Company, Multiple Intervenors and the PSC staff reached a three-year gas settlement that was conditionally approved by the PSC. The agreement eliminated the gas adjustment clause and established a gas commodity cost adjustment clause ("CCAC"). The Company's gas CCAC provides for the collection or pass back of certain increases or decreases from the base commodity cost of gas. The maximum annual risk or benefit to the Company is $2.25 million. All savings or excess costs beyond that amount flow to ratepayers.

Federal Income Taxes: As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. Deferred investment tax credits are amortized over the useful life of the underlying property.

Statement of Cash Flows: The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

Earnings per Share: Basic earnings per share ("EPS") is computed based on the weighted average number of common shares outstanding for the period. The number of options outstanding at December 31, 1998, 1997 and 1996 that could potentially dilute basic EPS, (but are considered antidilutive for each period because the options exercise price was greater than the average market price of common shares), is immaterial. Therefore, the calculation of both basic and dilutive EPS are the same for each period.

Segment Disclosure: For the fiscal year ending December 31, 1998, the Company adopted Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information." SFAS No. 131 supersedes Statement of Financial Accounting Standards No. 14 "Financial Reporting for Segments of a Business Enterprise," replacing the "industry segment" approach with the "management" approach. The management approach requires financial information to be disclosed for segments whose operating results are reviewed by the chief operating officer for decisions on resource allocation. It also requires related disclosures about products and service, geographic areas and major customers. The adoption of SFAS No. 131 did not affect results of operations or financial position, but did affect the disclosure of segment information.

Derivatives: In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities." The new standard requires companies to record derivatives on the balance sheet as assets or liabilities, measured at fair value. Gains or losses resulting from the changes in the values of the derivatives will be accounted for depending on the use of the derivative and whether it qualifies for hedge accounting. The Company will be required to adopt this standard by fiscal year beginning January 1, 2000. The Company has identified the indexed swap contracts (see Note 10. - "Fair Value of Financial and Derivative Financial Instruments") as derivative instruments and has recorded a liability at fair value under SFAS No. 80, "Accounting for Futures Contracts." These indexed swap contracts qualify as hedges of future purchase commitments and will continue to under SFAS No. 133. The Company continues to assess the applicability of this new standard to other contractual obligations.

Energy Trading: The Emerging Issues Task Force of the FASB recently reached a consensus on Issue 98-10, "Accounting for Energy Trading and Risk Management Activities." The Company does not believe that the accounting requirements of Issue 98-10 will have a significant impact on its financial position or results of operations. Niagara Mohawk Energy, Inc., a wholly owned subsidiary of the Company, engages in trading activities, and such transactions are accounted for on a mark-to-market basis with changes in fair value recognized as a gain or loss in the period of change. The effects of these trading activities on the Company's 1998 and 1997 results of operations were not material.

Comprehensive Income: While the primary component of comprehensive income is the Company's reported net income or loss, the other components of comprehensive income relate to foreign currency translation adjustments and unrealized gains and losses associated with certain investments held as available for sale.

Reclassifications: Certain amounts from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1998 presentation.

NOTE 2. Rate and Regulatory Issues and Contingencies

The Company's financial statements conform to GAAP, including the accounting principles for rate-regulated entities with respect to its regulated operations. The Company discontinued application of regulatory accounting principles to the Company's fossil and hydro generation business as of December 31, 1996 which resulted in a $103.6 million charge against 1996 income as an extraordinary non-cash charge. Substantively, SFAS No. 71 permits a public utility, regulated on a cost-of-service basis, to defer certain costs, which would otherwise be charged to expense, when authorized to do so by the regulator. These deferred costs are known as regulatory assets, which in the case of the Company are approximately $5.5 billion at December 31, 1998. These regulatory assets are probable of recovery.

Under *PowerChoice*, a regulatory asset was established for the costs of the MRA and will be amortized over a period generally not to exceed ten years. The Company's rates under *PowerChoice* have been designed to permit recovery of the MRA regulatory asset. In approving *PowerChoice*, the PSC limited the estimated value of the MRA regulatory asset that could be recovered, which resulted in a charge to the second quarter of 1998 earnings of $263.2 million upon the closing of the MRA.

The Company, as part of the MRA, entered into restated contracts with eight IPPs. The contracts have a term of ten years and are structured as indexed swap contracts where the Company receives or makes payments to the IPP Parties based upon the differential between the contract price and a market reference price for electricity. The Company has recorded the liability for these contractual obligations and recorded a corresponding regulatory asset since payments under these restated contracts are authorized under *PowerChoice*. See Note 10. - "Fair Value of Financial and Derivative Financial Instruments."

Under *PowerChoice*, the Company's remaining electric business (nuclear generation and electric transmission and distribution business) will continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company continues to apply SFAS No. 71 to these businesses. Also, the Company's IPP contracts, including those restructured under the MRA, will continue to be the obligations of the regulated business. Under *PowerChoice*, the Company was required to net certain regulatory assets and liabilities for future ratemaking consideration and has reflected these changes in its December 31, 1998 balance sheet.

The EITF of the FASB reached a consensus on Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No.

101" in July 1997. EITF 97-4 does not require the Company to earn a return on regulatory assets that arise from a deregulating transition plan in assessing the applicability of SFAS No. 71. The Company believes that the regulated cash flows to be derived from prices it will charge for electric service over the next 10 years, including the Competitive Transition Charge ("CTC") assuming no unforeseen reduction in demand or bypass of the CTC or exit fees, will be sufficient to recover the MRA Regulatory Asset and to provide recovery of and a return on the remainder of its assets, as appropriate. In the event the Company determines, as a result of lower than expected revenues and/or higher than expected costs, that its net regulatory assets are not probable of recovery, it can no longer apply the principles of SFAS No. 71 and would be required to record an after-tax non-cash charge against income for any remaining unamortized regulatory assets and liabilities. If the Company could no longer apply SFAS No. 71, the resulting charge would be material to the Company's reported financial condition and results of operations and adversely effect the Company's ability to pay dividends.

PowerChoice requires the Company to divest its portfolio of fossil and hydro generating assets. As of December 31, 1998, the Company has agreed to sell its hydroelectric generating plants and coal-fired stations for $780 million. These assets have a total book value of approximately $639 million. The remaining oil and gas-fired plants in Albany and Oswego and the Company's 25% ownership in the Roseton Steam Station have a book value of approximately $411 million. The *PowerChoice* agreement provides for deferral and future recovery of net losses, if any, resulting from the sale of the portfolio. The Company believes that it will be permitted to record a regulatory asset for any such losses in accordance with EITF 97-4. The Company has determined that there is no impairment of this portfolio of assets.

The Company has recorded the following regulatory assets on its Consolidated Balance Sheets reflecting the rate actions of its regulators:

MRA Regulatory Asset represents the recoverable costs to terminate, restate or amend IPP Party contracts, which have been deferred and are being amortized and recovered under the PowerChoice agreement. The MRA Regulatory Asset is being amortized generally over ten years, beginning September 1, 1998.

Regulatory Tax Asset represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are amortized and recovered as the related temporary differences reverse. In January 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures that required adoption of SFAS No. 109 on a revenue-neutral basis.

Indexed Swap Contract Regulatory Asset represents the fair value of the difference between estimated future market prices and the indexed contract prices for the notional quantities of power in the restated PPA contracts. In accordance with the MRA, this asset will be amortized over ten years ending in June 2008, as notional quantities are settled. The amount of this regulatory asset will fluctuate as estimates of future market and contract prices change over the term of the contracts.

Deferred Environmental Restoration Costs represent the Company's share of the estimated costs to investigate and perform certain remediation activities at both Company-owned sites and non-owned sites with which it may be associated. The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. *PowerChoice* and the Company's gas settlement provide for the recovery of these costs over the settlement periods. The Company believes future costs, beyond the settlement periods, will continue to be recovered in rates. See Note 9. - "Environmental Contingencies."

Unamortized Debt Expense represents the costs to issue and redeem certain long-term debt securities, which were retired prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

Postretirement Benefits other than Pensions represent the excess of such costs recognized in accordance with SFAS No. 106 over the amount received in rates. In accordance with the PSC policy statement, postretirement benefit costs other than pensions were phased into rates generally over a five-year period and amounts deferred are being amortized and recovered over a period of approximately 15 years.

Substantially all of the Company's regulatory assets described above are being amortized to expense and recovered in rates over periods approved in the Company's electric and gas rate cases, respectively.

NOTE 3. Nuclear Operations

The Company is the owner and operator of the 613 MW Unit 1 and the operator and a 41% co-owner of the 1,143 MW Unit 2. The remaining ownership interests are Long Island Power Authority ("LIPA") - 18%; New York State Electric and Gas Corporation (NYSEG) - 18%; Rochester Gas and Electric Corporation (RG&E) - 14%; and Central Hudson Gas and Electric Corporation (Central Hudson) - 9%. Unit 1 was placed in commercial operation in 1969 and Unit 2 in 1988.

In January 1999, the Company announced plans to pursue the sale of its nuclear assets, which will require approval from the PSC. The Company is unable to predict if a sale will occur and the timing of such sale.

At December 31, 1998, the net book value of the Company's nuclear generating assets was approximately $1.6 billion, excluding the reserve for decommissioning. In addition, the Company has other assets of approximately $0.5 billion. These assets include the decommissioning trusts and regulatory assets, primarily due to the deferral of income taxes.

Nuclear Plant Decommissioning: The Company's site specific cost estimates for decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1998 are as follows:

	Unit 1	Unit 2
Site Study (year)	1995	1995
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2028
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in January 1999 dollars)		
	In millions of dollars	
Radioactive Components	$498	$207
Non-radioactive Components	121	50
Fuel Dry Storage/Continuing Care	80	45
	$699	$302

The Company estimates that by the time decommissioning is completed, the above costs will ultimately amount to $1.7 billion and $0.9 billion for Unit 1 and Unit 2, respectively, using approximately 3.5% as an annual inflation factor.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant ramp down, insurance and property taxes. In 1999 dollars, these costs are expected to amount to $123 million and $65 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $210 million and $190 million for Unit 1 and the Company's share of Unit 2, respectively, by the time decommissioning is expected to be completed.

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning radioactive portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. The allowance for Unit 1 and the Company's share of Unit 2 was approximately $25.2 million, for the year ended December 31, 1998. This is $1.5 million higher than 1997 when the NRC minimum cost requirements were authorized in rates by the PSC. *PowerChoice*, which was implemented September 1, 1998, permits rate recovery for all radioactive and non-radioactive cost components for both units, including post-shutdown costs, based upon the amounts estimated in the 1995 site specific studies described above, which are higher than the NRC minimum. For 1999, the annual decommissioning allowance will increase to $42 million of which $28 million is for radioactive components and $14 million is for non-radioactive components. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that if decommissioning costs are higher than currently estimated, the costs would ultimately be included in the rate process.

Decommissioning costs recovered in rates are reflected in "Accumulated depreciation and amortization" on the balance sheet and amount to $315.5 million and $266.8 million at December 31, 1998 and 1997, respectively for both units. Additionally at December 31, 1998, the fair value of funds accumulated in the Company's external trusts were $192.4 million for Unit 1 and $64.9 million for its share of Unit 2. The trusts are included in "Other Property and Investments." Earnings on the external trust aggregated $81.1 million through December 31, 1998, including $27.9 million of unrealized market gains, and, because the earnings are available to fund decommissioning, have also been included in "Accumulated depreciation and amortization." Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund, which has an accumulated balance of $51.2 million at December 31, 1998.

Nuclear Liability Insurance: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

With respect to a nuclear incident at a licensed reactor, the statutory limit for the protection of the public under the Price-Anderson Amendments Act of 1988 which is in excess of the $200 million of nuclear liability insurance, is currently $9.15 billion without the 5% surcharge discussed below. This limit would be funded by assessments of up to $83.9 million for each of the 109 presently licensed nuclear reactors in the United States, payable at a rate not to exceed $10 million per reactor, per year, per incident. Such assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims. With the 5% surcharge included, the statutory limit is $9.6 billion.

The Company's interest in Units 1 and 2 could expose it to a maximum potential loss, for each accident, of $124.2 million (with 5% assessment) through assessments of $14.1 million per year in the event of a serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations, whether or not a nuclear incident actually occurs.

Nuclear Property Insurance: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the American Nuclear Insurers (ANI). In addition, there is $2.25 billion in excess of the $500 million primary nuclear insurance with Nuclear Electric Insurance Limited ("NEIL"). The total nuclear property insurance is $2.75 billion. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement power during prolonged accidental outages. The insurance provides coverage for outages for 156 weeks, after a 21-week waiting period. NEIL insurance is subject to retrospective premium adjustment under which the Company could be assessed up to approximately $9.9 million per loss.

Low Level Radioactive Waste: The Company currently uses the Barnwell, South Carolina waste disposal facility for low level radioactive waste. However, continued access to Barnwell is not assured, and the Company has implemented a low level radioactive waste management program so that Unit 1 and Unit 2 are prepared to properly handle interim on-site storage of low level radioactive waste for at least a ten-year period.

Under the Federal Low Level Waste Policy Amendment Act of 1985, New York State was required by January 1, 1993 to have arranged for the disposal of all low level radioactive waste within the state or in the alternative, contracted for the disposal at a facility outside the state. To date, New York State has made no funding available to support siting for a disposal facility.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (the "Nuclear Waste Act") established a cost of $.001 per KWh of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which the Company initially plans to ship irradiated fuel to an approved DOE disposal facility. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010. In July 1996, the United States Circuit Court of Appeals for the District of Columbia ruled that the DOE has an obligation to accept spent fuel from the nuclear industry by January 31, 1998 even though a permanent storage site would not be ready by then. The DOE did not appeal this decision. On January 31, 1997, the Company joined a number of other utilities, states, state agencies and regulatory commissions in filing a suit in the U.S. Court of Appeals for the District of Columbia against the DOE. The suit requested the court to suspend the utilities payments into the Nuclear Waste Fund and to place future payments into an escrow account until the DOE fulfills its obligation to accept spent fuel. The DOE did not meet its January 31, 1998 deadline and indicated it was not obligated to provide a financial remedy for delay. On November 14, 1997 the United States Court of Appeals for the District of Columbia Circuit issued a writ of mandamus precluding DOE from excusing its own delay on the grounds that it has not yet prepared a permanent repository or interim storage facility. On December 11, 1997, 27 utilities, including the Company, petitioned the DOE to suspend their future payments to the Nuclear Waste Fund until the DOE begins moving fuel from their plant sites. The petition further sought permission to escrow payments to the waste fund beginning in February 1998. On January 12, 1998, the DOE denied the petition. In 1998, both the House and the U.S. Senate passed legislation to reform the federal government's spent nuclear fuel disposal policy. This legislation authorized DOE to construct an interim spent fuel storage facility to accommodate acceptance of spent fuel beginning no later than June 2003. Additionally, this legislation required the payment of one-time fees by electric utilities for the disposal of fuel irradiated prior to 1983 to be paid to the Nuclear Waste Fund no later than September 30, 2001. However, this legislation was never sent to the President for approval. It is expected that similar legislation will be introduced in 1999. As of December 31, 1998, the Company has recorded a liability of $120.2 million for the disposal of nuclear fuel irradiated prior to 1983. The Company is unable to predict the outcome of this matter.

The Company has several alternatives under consideration to provide additional spent fuel storage facilities, as necessary. Each alternative will likely require NRC approval, may require other regulatory approvals and would likely require incurring additional costs, which the Company has included in its decommissioning estimates for both Unit 1 and its share of Unit 2. In May 1998, the Company requested approval from the NRC to add additional racks in the spent fuel pool at Unit 1 that will allow almost 50% more spent fuel to be stored in the pool. The NRC is expected to make a decision during March 1999. If approved, the additional racks will provide Unit 1 with enough spent fuel storage through the end of Unit 1's licensing period. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

NOTE 4. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly owned generating facilities at December 31, 1998. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income. Under *PowerChoice*, the Company will divest all of its fossil and hydro generation assets with a net book value of $1.1 billion, including its interests in jointly owned fossil facilities.

		In thousands of dollars		
	Percentage Ownership	Utility Plant	Accumulated Depreciation	Construction Work in Progress
Roseton Steam Station				
Units No. 1 and 2 *(a)*	25	$ 96,192	$ 57,639	$ 740
Oswego Steam Station				
Unit No. 6 *(b)*	76	$ 270,316	$133,678	$ 140
Nine Mile Point Nuclear Station				
Unit No. 2 *(c)*	41	$1,505,319	$362,003	$8,239

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation ("Central Hudson"), the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). Output of Roseton Units No. 1 and 2, which have a capability of 1,200,000 KW, is shared in the same proportions as the cotenants' respective ownership interests. Central Hudson intends to sell its generation assets and will include the Company's share of Roseton in its sale, which Central Hudson expects to conclude in 2000.

(b) The Company is the operator. The remaining ownership interest is Rochester Gas and Electric ("RG&E") (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 KW, is shared in the same proportions as the cotenants' respective ownership interests. The Company will sell RG&E's share in its auction of fossil generation assets.

(c) The Company is the operator. The remaining ownership interests are Long Island Power Authority ("LIPA") (18%), New York State Electric & Gas Corporation ("NYSEG") (18%), RG&E (14%), and Central Hudson (9%). Output of Unit 2, which has a capability of 1,143,000 KW, is shared in the same proportions as the cotenants' respective ownership interests.

NOTE 5. Capitalization

Capital Stock

The Company is authorized to issue 250,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1996, 1997 and 1998:

	Common Stock $1 par value		Preferred Stock $100 par value			Preferred Stock $25 par value			Capital Stock Premium and Expense (Net)*	Accumulated Other Comprehensive Income*
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*		
December 31, 1995:	144,332,123	$144,332	2,358,000	$210,000	$25,800*(a)*	12,408,005	$230,000	$80,200*(a)*	$1,793,798	($9,551)
Issued	33,091	33	—	—	—	—	—	—	214	
Redemptions			(18,000)	—	(1,800)	(344,000)	—	(8,600)	203	
Unrealized gain (loss) on securities (net of tax)										(231)
Foreign currency translation adjustment										(708)
December 31, 1996:	144,365,214	$144,365	2,340,000	$210,000	$24,000*(a)*	12,064,005	$230,000	$71,600*(a)*	$1,794,215	($10,490)
Issued	54,137	54	—	—	—	—	—	—	426	
Redemptions			(18,000)	—	(1,800)	(282,801)	—	(7,070)	98	
Unrealized gain (loss) on securities (net of tax)										6
Foreign currency translation adjustment										(4,567)
December 31, 1997:	144,419,351	$144,419	2,322,000	$210,000	$22,200*(a)*	11,781,204	$230,000	$64,530*(a)*	$1,794,739	($15,051)
Issued	42,945,512	42,946	—	—	—	—	—	—	563,540	
Redemptions			(18,000)	—	(1,800)	(332,801)	—	(8,320)	101	—
Unrealized gain (loss) on securities (net of tax)										304
Foreign currency translation adjustment										(6,896)
December 31, 1998:	187,364,863	$187,365	2,304,000	$210,000	$20,400*(a)*	11,448,403	$230,000	$56,210*(a)*	$2,358,380	($21,643)

* *In thousands of dollars*

(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1998 was $ (22,344).
The cumulative amount of unrealized gain on securities at December 31, 1998 was $ 701.

Non-Redeemable Preferred Stock (Optionally Redeemable)

The Company had certain issues of preferred stock which provide for optional redemption at December 31, as follows:

Series	Shares	In thousands of dollars 1998	1997	Redemption price per share *(Before adding accumulated dividends)*
Preferred $100 par value:				
3.40%	200,000	$ 20,000	$ 20,000	$103.50
3.60%	350,000	35,000	35,000	104.85
3.90%	240,000	24,000	24,000	106.00
4.10%	210,000	21,000	21,000	102.00
4.85%	250,000	25,000	25,000	102.00
5.25%	200,000	20,000	20,000	102.00
6.10%	250,000	25,000	25,000	101.00
7.72%	400,000	40,000	40,000	102.36
Preferred $25 par value:				
9.50%	6,000,000	150,000	150,000	25.00
Adjustable Rate —				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.00
		$440,000	$440,000	

Mandatorily Redeemable Preferred Stock

At December 31, the Company had certain issues of preferred stock, as detailed below, which provide for mandatory and optional redemption. These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series). The option to redeem additional amounts is not cumulative.

	Shares		*In thousands of dollars*		Redemption price per share *(Before adding accumulated dividends)*	
Series	1998	1997	1998	1997	1998	Eventual minimum
Preferred $100 par value:						
7.45%	204,000	222,000	$ 20,400	$ 22,200	$101.45	$100.00
Preferred $25 par value:						
7.85%	548,403	731,204	13,710	18,280	25.00	25.00
8.375%	—	100,000	—	2,500	—	
Adjustable Rate – Series B	1,700,000	1,750,000	42,500	43,750	25.00	25.00
			76,610	86,730		
Less sinking fund requirements			7,620	10,120		
			$ 68,990	$76,610		

The Company's five-year mandatory sinking fund redemption requirements for preferred stock are as follows:

	Redemption Requirements *(in thousands)*
1999	$7,620
2000	7,620
2001	7,620
2002	3,050
2003	3,050

Long-Term Debt

The Company's long-term debt increased significantly upon the closing of the MRA on June 30, 1998. The MRA was largely financed through the Senior Notes. The Senior Notes are unsecured obligations of the Company and rank pari passu in right of payment to its First Mortgage Bonds, the senior bank financing and unsecured medium term notes. The Company's ability to make common stock dividend payments may be restricted under certain covenants of the Senior Notes relating to fixed charge coverages and operating cash flow as defined in the indenture. These restrictions are no longer applicable once the Senior Notes become rated as investment grade.

In addition, the Company is obligated to use 85% of the net proceeds of the sales of the generation assets to reduce its senior debt outstanding within 180 days after the receipt of such proceeds. As of December 31,1998, the Company has entered into agreements for the sale of its two largest components of its fossil and hydroelectric generating portfolio for $780 million. It is anticipated that transaction closings will occur in mid-1999 after receipt of the necessary regulatory approvals.

Several series of First Mortgage Bonds and Promissory Notes were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $414 million of such securities bear interest at a daily adjustable interest rate (with a Company option to convert to other rates, including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 3.39 % for 1998 and 3.63% for 1997 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities or to refund outstanding tax-exempt bonds and notes (see Note 6). In November 1998, the Company refinanced its 8-7/8% series of tax exempt bonds issued through NYSERDA at a rate of 5.15%.

Other long-term debt in 1998 consists of obligations under capital leases of approximately $26.3 million, a liability to the DOE for nuclear fuel disposal of approximately $120.2 million and a liability for IPP contract terminations not related to the MRA of approximately $28.0 million. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1998, excluding capital leases, in millions, are approximately $309, $719, $715, $635 and $705, respectively and exclude acceleration of debt repayment associated with the sale of fossil and hydro assets.

Long-term debt at December 31 consisted of the following:

Series	Due	1998	1997
		In thousands of dollars	
First mortgage bonds:			
6 1/2%	1998	$ —	$ 60,000
9 1/2%	2000	150,000	150,000
6 7/8%	2001	210,000	210,000
9 1/4%	2001	100,000	100,000
5 7/8%	2002	230,000	230,000
6 7/8%	2003	85,000	85,000
7 3/8%	2003	220,000	220,000
8%	2004	300,000	300,000
6 5/8%	2005	110,000	110,000
9 3/4%	2005	150,000	150,000
7 3/4%	2006	275,000	275,000
*6 5/8%	2013	45,600	45,600
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	150,000
8 1/2%	2023	165,000	165,000
7 7/8%	2024	210,000	210,000
*8 7/8%	2025	—	75,000
*5.15%	2025	75,000	—
*7.2%	2029	115,705	115,705
Total First Mortgage Bonds		2,741,305	2,801,305
Senior Notes:			
6 1/2%	1999	300,000	—
7%	2000	450,000	—
7 1/8%	2001	400,000	—
7 1/4%	2002	400,000	—
7 3/8%	2003	400,000	—
7 5/8%	2005	400,000	—
7 3/4%	2008	600,000	—
8 1/2%	2010	500,000	—
Unamortized discount on 8 1/2% Senior Note		(156,216)	
Total Senior Notes		3,293,784	—
Promissory notes:			
*Adjustable Rate Series due			
2015		100,000	100,000
2023		69,800	69,800
2025		75,000	75,000
2026		50,000	50,000
2027		25,760	25,760
2027		93,200	93,200
Term Loan Agreement		105,000	105,000
Unsecured Medium Term Notes: Various rates, due 2000-2004		20,000	20,000
Other		174,462	154,295
Unamortized premium (discount)		(18,846)	(9,884)
TOTAL LONG-TERM DEBT		6,729,465	3,484,476
Less long-term debt due within one year		312,240	67,095
		$6,417,225	$3,417,381

**Tax-exempt pollution control related issues*

NOTE 6. Bank Credit Arrangements

The Company has an $804 million senior bank financing with a bank group consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA, discussed in Note 5. As of December 31, 1998, the amount outstanding under the senior bank financing was $529 million, consisting of $105 million under the term loan facility and $424 million of letters of credit, leaving the Company with $275 million of borrowing capability under the financing. The senior bank financing was amended as of June 30, 1998. The amendment, which included an extension of the term from June 30, 1999 to June 1, 2000, also accommodates the holding company structure and permits the auction of the fossil and hydro generating assets. In addition, the amendment limits the annual amount of common stock dividend payments that can be paid by the regulated business. The limit is based upon the amount of net income each year, plus a specified amount ranging from $50 million in 1998 to $100 million in 2000. The interest rate applicable to the facility is variable based on certain rate options available under the agreement and currently approximates 6.5% (but capped at 15%). In addition, the Company's unregulated subsidiaries have an agreement with banks for letters of credit totaling up to $25 million. The Company did not have any short-term debt outstanding at December 31, 1998 and 1997.

NOTE 7. Federal and Foreign Income Taxes

See Note 9 - "Tax Assessments."

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1998	1997	1996
United States	$(206,372)	$ 315,027	$ 269,128
Foreign	8,227	(1,621)	28,522
Consolidating eliminations	10,592	(3,476)	(17,402)
Income before extraordinary item and income taxes	$(187,553)	$ 309,930	$ 280,248

Following is a summary of the components of Federal and foreign income tax and a reconciliation between the amount of Federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory tax rate:

		In thousands of dollars		
		1998	1997	1996 *
Components of Federal and foreign income taxes:				
Current tax expense:	Federal	$ (155,320)	$ 77,565	$ 96,011
	Foreign	—	—	3,708
		(155,320)	77,565	99,719
Deferred tax expense:	Federal	84,466	47,836	382
	Foreign	4,126	1,194	2,393
		88,592	49,030	2,775
Total		$ (66,728)	$126,595	$102,494
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:				
Computed tax		$(65,644)	$108,475	$ 98,087
Increase (reduction) attributable to flow-through of certain tax adjustments:				
Depreciation		20,808	34,926	26,216
Cost of removal		(7,859)	(8,168)	(8,849)
Allowance for funds used during construction		(4,207)	(2,952)	(1,431)
Expiring foreign tax credits		10,053	—	—
Pension settlement amortization		(3,317)	(2,391)	(4,721)
Debt premium & mortgage recording tax		(9,408)	23	1,252
Deferred investment tax credit amortization		(7,454)	(7,454)	(8,018)
Other		300	4,136	(42)
		(1,084)	18,120	4,407
Federal and foreign income taxes		$(66,728)	$126,595	$102,494

* Does not include the deferred tax benefit of $36,273 in 1996 associated with the extraordinary item for the discontinuance of regulatory accounting principles

At December 31, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars	
	1998	1997
Alternative minimum tax	$ (82,621)	$ (17,448)
Unbilled revenue	(81,685)	(88,859)
Non-utilized NOL carry forward	(1,161,898)	—
Other	(290,035)	(247,438)
Total deferred tax assets	(1,616,239)	(353,745)
Depreciation related	1,292,582	1,358,827
Investment tax credit related	76,418	79,858
MRA terminated IPP contracts	1,415,977	—
Other	342,679	302,092
Total deferred tax liabilities	3,127,656	1,740,777
Accumulated deferred income taxes	$ 1,511,417	$1,387,032

In December 1998, the Company received a ruling from the IRS to the effect that the amount of cash and the value of common stock that was paid to the terminated IPP Parties will be currently deductible and generate a substantial net operating loss for federal income tax purposes, such that the Company will not pay federal income taxes for 1998. Further, the Company has carried back unused NOL to the years 1996 and 1997, and also for the years 1988 through 1990, which has resulted in refunds of $130 million and $5 million, respectively, that were received in January 1999. In addition, the Company anticipates that it will be able to utilize the remaining $3.3 billion NOL carryforward prior to its expiration date in 2019. The Company's ability to utilize the NOL generated as a result of the MRA could be limited under the rules of section 382 of the Internal Revenue Code if certain changes in the Company's common stock ownership were to occur in the future.

NOTE 8. Pension and Other Retirement Plans

During 1998, the Company's non-contributory defined benefit pension plan covering substantially all employees was amended to include a cash balance benefit in which the participant has an account to which amounts are credited based on qualifying compensation and with interest determined annually based on average annual 30-year Treasury bond yield. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain officers. In addition, the Company provides certain contributory health care and life insurance benefits for active and retired employees and dependents.

The changes in benefit obligations, plan assets and plan funded status for these pension and other retirement plans as of, and for the year ended December 31, are summarized as follows:

	In thousands of dollars			
	Pension Benefits		Other Retirement Benefits	
Change in benefit obligation:	1998	1997	1998	1997
Benefit obligation at January 1	$ 1,172,428	$1,027,781	$ 519,851	$ 470,730
Service cost	30,430	27,106	14,338	12,255
Interest cost	79,748	74,984	35,338	34,829
Benefits paid to participants	(75,650)	(57,100)	(32,917)	(28,602)
Plan amendments	33,694	4,602	(6,579)	—
Actual (gain) loss	61,547	95,055	17,589	30,639
Benefit obligation at December 31	1,302,197	1,172,428	547,620	519,851
Change in plan assets:				
Fair value of plan assets at January 1	1,304,338	1,159,822	181,101	143,071
Contributions	12,446	12,446	9,466	13,542
Net return on plan assets	198,943	188,239	19,479	24,488
Benefits paid to participants	(69,215)	(56,169)	—	—
Fair value of plan assets at December 31	1,446,512	1,304,338	210,046	181,101
Funded status	144,315	131,910	(337,574)	(338,750)
Unrecognized initial obligation	16,887	19,446	152,460	163,350
Unrecognized net gain from actual return on plan assets	(360,450)	(265,100)	—	—
Unrecognized net loss (gain) from past experience different from that assumed	41,914	(19,920)	55,335	48,840
Unrecognized prior service cost	79,269	50,473	(27,532)	(30,460)
Benefits liability on the consolidated balance sheet	$ (78,065)	$ (83,191)	$ (157,311)	$ (157,020)

The non-qualified executive pension plan has no plan assets due to the nature of the plan, and therefore, has an accumulated benefit obligation in excess of plan assets of $8,816 and $6,243 at December 31, 1998 and 1997, respectively.

The following table summarizes the components of the net annual benefit costs.

	In thousands of dollars					
	Pension Benefits			**Other Retirement Benefits**		
	1998	1997	1996	1998	1997	1996
Service cost	$ 30,430	$ 27,106	$ 24,951	$ 14,338	$ 12,255	$ 12,935
Interest cost	79,748	74,984	71,729	35,338	34,829	37,495
Expected return on plan assets	(95,472)	(84,859)	(78,083)	(16,752)	(13,234)	(8,138)
Amortization of the initial obligation	2,559	2,559	2,559	10,890	10,890	13,507
Amortization of gains and losses	(8,408)	(9,226)	(6,540)	8,367	6,967	6,987
Amortization of prior service costs	4,899	3,892	3,638	(9,508)	(8,745)	(5,830)
Net benefit cost (1)	$ 13,756	$ 14,456	$ 18,254	$ 42,673	$ 42,962	$ 56,956

(1) A portion of the benefit costs relates to construction labor, and accordingly, is allocated to construction projects.

Weighted-average assumptions as of December 31:	**Pension Benefits**		**Other Retirement Benefits**	
	1998	1997	1998	1997
Discount rate	6.75%	7.00%	6.75%	7.00%
Expected return on plan assets	9.25	9.25	9.25	9.25
Rate of compensation increase (plus merit increases)	2.50	2.50	N/A	N/A
Health care cost trend rate:				
Under age 65	N/A	N/A	7.00	7.00
Over age 65	N/A	N/A	6.00	6.00

The assumed health cost trend rates decline to 5% in 2000 and remain at that level thereafter. The assumed health cost trend rates can have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	In thousands of dollars	
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 2,076	$ (1,799)
Effect on health care component of the accumulated postretirement benefit obligation	32,906	(28,465)

The Company recognizes the obligation to provide postemployment benefits if the obligation is attributable to employees' past services, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. At December 31, 1998 and 1997, the Company's postemployment benefit obligation is approximately $15.3 million and $13.3 million, respectively.

NOTE 9. Commitments and Contingencies

Long-term Contracts for the Purchase of Electric Power: At January 1, 1999, the Company had long-term contracts to purchase electric power from the following generating facilities owned by NYPA:

Facility	Expiration Date of Contract	Purchased Capacity in MW	Estimated Annual Capacity Cost
Niagara hydroelectric project	2007	951	$27,667,000
St. Lawrence hydroelectric project	2007	104	1,248,000
Blenheim-Gilboa pumped storage generating station	2002	270	7,452,000
		1,325	$36,367,000

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts was approximately, in millions, $93.1, $91.0 and $93.3 for the years 1998, 1997 and 1996, respectively. The Company continues to have a contract with NYPAs Fitzpatrick nuclear facility to purchase for resale up to 46 MW of power for NYPA's economic development customers.

Under the requirements of PURPA, the Company is required to purchase power generated by IPPs, as defined therein. The Company has 118 PPAs with 125 facilities, amounting to approximately 1,125 MW of capacity at December 31, 1998. All of this amount is considered firm, but excludes PPAs that provide energy only. The following table shows the estimated payments for fixed costs (capacity) and variable costs (capacity, energy and related taxes) the Company estimates it will be obligated to make under these contracts, excluding the over market obligation under the indexed swap contracts. See Note 10. Fair Value of Financial and Derivative Financial Instruments. These payments have been significantly reduced by the consummation of the MRA. The MRA was consummated on June 30, 1998 with 14 IPPs. The MRA allowed the Company to terminate, restate or amend 27 PPAs which represented approximately three quarters of the Company's over-market purchase power obligations. Under the terms of the MRA, the Company terminated 18 PPAs representing 1,092 MW of electric generating capacity, restated eight PPAs representing 535 MW of capacity and amended one PPA representing 42 MW of capacity. In addition, the Company is continuing to actively pursue other opportunities to reduce payments to IPPs that were not a party to the MRA.

The payments are subject to the tested capacity and availability of the facilities, scheduling and price escalation.

	In thousands of dollars		
	Fixed Costs	Variable Costs	
Year	Capacity	Capacity Energy and Taxes	Total
1999	$13,456	$392,029	$405,485
2000	13,793	412,177	425,970
2001	13,989	413,482	427,471
2002	14,288	425,357	439,645
2003	14,635	437,731	452,366

Fixed capacity costs (in the table above) relate to one 56 MW contract, where the Company is required to make capacity payments, including payments when the facility is not operating but available for service. The terms of this contract allows the Company to schedule energy deliveries and then pay for the energy delivered. Contracts relating to the remaining facilities in service at December 31, 1998, require the Company to pay only when energy is delivered, except when the Company decides that it would be better to pay a particular project a reduced energy payment to have the project reduce its high priced energy deliveries. The Company paid approximately $785 million, $1,106 million and $1,088 million in 1998, 1997 and 1996 for 9,700,000 MWh, 13,500,000 MWh and 13,800,000 MWh, respectively, of electric power under all IPP contracts.

Sale of Customer Receivables: The Company has established a single-purpose, financing subsidiary, NM Receivables LLC, whose business consists of the purchase and resale of an undivided interest in a designated pool of customer receivables, including accrued unbilled revenues. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold. NM Receivables LLC has its own separate creditors which, upon liquidation of NM Receivables LLC, will be entitled to be satisfied out of its assets prior to any value becoming available to the Company. The sale of receivables are in fee simple for a reasonably equivalent value and are not secured loans. Some receivables have been contributed in the form of a capital contribution to NM Receivables LLC in fee simple for reasonably equivalent value, and all receivables transferred to NM Receivables LLC are assets owned by NM Receivables LLC in fee simple and are not available to pay the parent Company's creditors.

At December 31, 1998 and 1997, $150 million and $144.1 million, respectively, of receivables had been sold by NM Receivables LLC to a third party. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a formula based loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. At December 31, 1998, the amount of additional receivables assigned to the purchaser, as a loss reserve, was approximately $40.0 million.

To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. Concentrations of credit risk to the purchaser with respect to accounts receivable are limited due to the Company's large, diverse customer base within its service territory. The Company generally does not require collateral, i.e., customer deposits.

Tax Assessments: The Internal Revenue Service ("IRS") conducted an examination of the Company's federal income tax returns for the years 1989 and 1990 and issued a Revenue Agents' Report (RAR). The IRS raised an issue concerning the deductibility of payments made to IPPs in accordance with certain contracts that include a provision for a tracking account. In late November 1998, the Company received a final settlement letter from the IRS allowing the deduction of these IPP payments. The IRS also conducted an examination of the Company's federal income tax returns for the years 1991 through 1993 and issued an RAR in the second quarter of 1998. Based upon the Company's review of the report, the Company does not believe that the findings will have a material impact on its financial position or results of operation.

Environmental Contingencies: The public utility industry typically utilizes and/or generates in its operations a broad range of hazardous and potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and aid in compliance with such requirements. The Company is also currently conducting a program to investigate and remediate, as necessary to meet current environmental standards, certain properties associated with former gas manufacturing and other properties which the Company has learned may be contaminated with industrial waste, as well as investigating identified industrial waste sites as to which it may be determined that the Company contributed. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 136 sites with which it has been or may be associated, including 82 which are Company-owned. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs. Although one party can, as a matter of law, be held liable for all of the remedial costs at a site, regardless of fault, in practice costs are usually allocated among PRPs. The Company has denied any responsibility at certain of these PRP sites and is contesting liability accordingly.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) if necessary, determine the appropriate remedial actions and (3) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since investigations are ongoing for most sites, the estimated cost of remedial action is subject to change.

Estimates of the cost of remediation and post-remedial monitoring are based upon a variety of factors, including identified or potential contaminants; location, size and use of the site; proximity to sensitive resources; status of regulatory investigation and knowledge of activities at similarly situated sites. Additionally, the Company's estimating process includes an initiative where these factors are developed and reviewed using direct input and support obtained from the DEC. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several.

As a consequence of site characterizations and assessments completed to date and negotiations with PRPs, the Company has accrued a liability in the amount of $220 million, which is reflected in the Company's Consolidated Balance Sheets at December 31, 1998. The potential high end of the range is presently estimated at approximately $710 million, including approximately $340 million in the unlikely event the Company is required to assume 100% responsibility at non-owned sites. The amount accrued at December 31, 1998, incorporates a method to estimate the liability for 22 of the Company's largest sites, which relies upon a decision analysis approach. This method includes developing several remediation approaches for each of the 22 sites, using the factors previously described, and then assigning a probability to each approach. The probability represents the Company's best estimate of the likelihood of the approach occurring using input received directly from the DEC. The probable costs for each approach are then calculated to arrive at an expected value. While this approach calculates a range of outcomes for each site, the Company has accrued the sum of the expected values for these sites. The amount accrued for the Company's remaining sites is determined through feasibility studies or engineering estimates, the Company's estimated share of a PRP allocation or where no better estimate is available, the low end of a range of possible outcomes is used. In addition, the Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. *PowerChoice* provides for the continued application of deferral accounting for cost differences resulting from this effort.

In October 1997, the Company submitted a draft feasibility study to the DEC, which included the Company's Harbor Point site and five surrounding non-owned sites. The study indicates a range of viable remedial approaches, however, a final determination has not been made concerning the remedial approach to be taken. This range consists of a low end of $21 million and a high end of $360 million, with an expected value calculation of $56 million, which is included in the amounts accrued at December 31, 1998. The range represents the total costs to remediate the properties and does not consider contributions from other PRPs, the amount of which the Company is unable to estimate. The Company has received comments from the DEC on the draft feasibility study, which will facilitate completion of the feasibility study phase in the spring of 1999. At this time, the Company cannot definitively predict the nature of the DEC proposed remedial action plan or the range of remediation costs the DEC will require. While the Company does not expect to be responsible for the entire cost to remediate these properties, it is not possible at this time to determine its share of the cost of remediation.

In May 1995, the Company filed a complaint pursuant to applicable Federal and New York State law, in the U.S. District Court for the Northern District of New York against several defendants seeking recovery of past and future costs associated with the investigation and remediation of the Harbor Point and surrounding sites. The New York State Attorney General moved to dismiss the Company's claims against the state of New York, the New York State Department of Transportation and the Thruway Authority and Canal Corporation under the Comprehensive Environmental Response, Compensation and Liability Act. The Company opposed this motion. On April 3, 1998, the Court denied the New York State Attorney General's motion as it pertains to the Thruway Authority and Canal Corporation, and granted the motion relative to the state of New York and the Department of Transportation. On January 12, 1999, a pre-trial status conference was convened by the Court. The Court will be issuing an amended case management order that is expected to call for the close of discovery by the end of June 1999 and to establish December 1, 1999 as the trial ready date. As a result, the Company cannot predict the outcome of the pending litigation against the defendants or the allocation of the Company's share of the costs to remediate the Harbor Point and surrounding sites.

Where appropriate, the Company has provided notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant, industrial waste sites and sites for which the Company has been identified as a PRP. The Company has reached settlements with a number of insurance carriers, resulting in payments to the Company of approximately $39 million, net of costs incurred in pursuing recoveries. This amount is being amortized in rates generally over a 10-year period.

Construction Program: The Company is committed to an ongoing construction program to assure delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1999 through 2002, the period covered under the *PowerChoice* agreement, will require approximately $981 million, excluding AFC and nuclear fuel. For the years 1999 through 2002, the estimates, in millions, are $254, $240, $243, and $244, respectively, which excludes amounts relating to the Company's fossil and hydro generation assets. On December 3, 1998, the Company announced it had reached an agreement with an affiliate of Orion Power Holding, Inc. to sell its 72 hydroelectric generating plants and on December 23, 1998, the Company announced an agreement with NRG Energy, Inc. to sell its Huntley and Dunkirk coal-fired electric generating stations. It is anticipated that transaction closings will occur in mid-1999 after receipt of the necessary regulatory approvals. The Company continues to pursue the sale of its two oil and gas-fired plants in Albany and Oswego. The Company is unable to predict the outcome or timing of the divestiture of its two oil and gas-fired plants.

Gas Supply, Storage and Pipeline Commitments: In connection with its gas business, the Company has long-term commitments with a variety of suppliers and pipelines to purchase gas commodity, provide gas storage capability and transport gas commodity on interstate gas pipelines. The table below sets forth the Company's estimated commitments at December 31, 1998, for the next five years, and thereafter.

	(In thousands of dollars)	
Year	Gas Supply	Gas Storage/Pipeline
1999	$ 83,785	$ 96,772
2000	48,939	80,052
2001	46,565	65,942
2002	35,272	33,894
2003	35,272	11,926
Thereafter	99,921	58,474

With respect to firm gas supply commitments, the amounts are based upon volumes specified in the contracts giving consideration for the minimum take provisions. Commodity prices are based on New York Mercantile Exchange quotes and reservation charges, when applicable. For storage and pipeline capacity commitments, amounts are based upon volumes specified in the contracts, and represent demand charges priced at current filed tariffs.

At December 31, 1998, the Company's firm gas supply commitments extend through October 2006, while the gas storage and transportation commitments extend through October 2012. Beginning in May 1996, as a result of a generic rate proceeding, the Company was required to implement service unbundling, where customers could choose to buy natural gas from sources other than the Company. To date the migration has not resulted in any stranded costs since the PSC has allowed utilities to assign the pipeline capacity to the customers choosing another supplier. This assignment is allowed during a three-year period ending March 1999.

The PSC issued its Policy Statement in November 1998 concerning the future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment. The PSC Policy Statement states that utilities may no longer require capacity assignment or inclusion of capacity costs in transportation rates beyond April 1, 1999 to customers migrating to marketers except where specific operational and reliability requirements warrant.

In November 1998, the PSC approved the Company's proposed pilot program that would, effective December 1, 1998, no longer require assigning pipeline capacity and related costs upstream of the CNG Transmission System to customers migrating to transportation. However, the Company's proposed pilot program sought to continue to assign capacity on the CNG system until October 31, 1999, the expiration date of its current gas rate settlement agreement. A stranded cost recovery mechanism, in the form of a surcharge, was established to provide for the recovery of the unassigned pipeline capacity costs until October 31, 1999.

In December 1998, the Company notified the PSC that the Company's specific operational and reliability requirements continue to warrant certain mandatory capacity assignment and inclusion of capacity costs in transportation rates after April 1, 1999. The PSC noted in its PSC Policy Statement that it will provide LDCs with a reasonable opportunity to recover these strandable costs if they can demonstrate compliance with the PSC's directives to minimize such costs. The Company believes that it has taken numerous actions to reduce its capacity obligations and its potential stranded costs, but is unable to predict the outcome of this matter. The Company anticipates that this issue will be addressed in the individual negotiations with the PSC anticipated to begin during the second quarter of 1999.

NOTE 10. Fair Value of Financial and Derivative Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and Short-Term Investments: The carrying amount approximates fair value because of the short maturity of the financial instruments.

Long-Term Debt and Mandatorily Redeemable Preferred Stock: The fair value of fixed rate long-term debt and redeemable preferred stock is estimated using quoted market prices where available or discounting remaining cash flows at the Company's incremental borrowing rate. The carrying value of NYSERDA bonds and other long-term debt are considered to approximate fair value.

Derivative Financial Instruments: The fair value of futures and forward contracts are determined using quoted market prices and broker quotes.

Indexed Swap Contracts: Indexed swap contracts are ten-year financial contracts where the Company receives or makes payments to certain IPP Parties based upon the differential between the contract price and a market reference price for electricity. The contract prices are fixed for the first two years changing to an indexed pricing formula primarily related to gas prices, thereafter. Contract quantities are fixed for each year of the full ten-year term of the contracts and average 4.1 million MWh. The indexed pricing structure ensures that the price paid for energy and capacity will fluctuate relative to the underlying market cost of gas and general indices of inflation. At December 31, 1998 the Company projects that it will make the following payments to the IPP Parties for the years 1999 to 2003:

Year	*in thousands of dollars* Projected Payment
1999	$ 97,354
2000	97,688
2001	102,073
2002	103,552
2003	105,531

The financial instruments held or issued by the Company are for purposes other than trading. The estimated fair values of the Company's financial instruments are as follows:

	In thousands of dollars			
	1998		1997	
At December 31,	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments	$ 172,998	$ 172,998	$ 378,232	$ 378,232
Mandatorily redeemable preferred stock*	76,610	86,444	86,730	87,328
Long-term debt: First Mortgage bonds	2,741,305	2,905,141	2,801,305	2,878,368
Senior notes	3,293,784	3,324,777	—	—
Medium-term notes	20,000	23,290	20,000	22,944
Promissory notes	413,760	413,760	413,760	413,760
Other	253,195	253,195	229,634	229,634
Indexed swap contracts regulatory asset	693,363	693,363	—	—

At December 31, 1998, the Company's energy marketing subsidiary had no open trading positions. At December 31, 1997, the fair value of its long and short trading positions was approximately $54.7 million and $54.5 million, respectively. These fair values were less than the weighted average fair value of open positions for the year ending December 31, 1998 and greater than the weighted average fair value of open positions for the year ending December 31, 1997.

Transactions entered into for trading purposes are accounted for on a mark-to-market basis with changes in fair value recognized as a gain or loss in the period of change. At December 31, 1998, there were no open trading positions. At December 31, 1997, the open trading positions consisted of off-balance sheet electric and gas forward contracts. These positions consisted of long and short electric forward contracts with fair values of $45.3 million (1,878,000 MWhrs) and $44.3 million (1,778,000 MWhrs), respectively, and long and short gas forward contracts with fair values of $9.4 million (7.1 million Dth) and $10.2 million (7.3 million Dth), respectively. The effects of these trading activities on the Company's 1998 and 1997 results of operations were not material.

Activities for non-trading purposes generally consist of transactions entered into to hedge the market fluctuations of contractual and anticipated commitments. Gas futures are used for hedging purposes. Changes in market value of futures contracts relating to hedged items are deferred until the physical transaction occurs, at which time, income or loss is recognized. At December 31, 1998, the open non-trading positions consisted of long and short gas futures contracts with fair values of $4.8 million (2.5 million Dth) and $1.2 million (.7 million Dth), respectively. At December 31, 1997, the open non-trading positions consisted of long and short gas futures contracts with fair values of $5.2 million (2.3 million Dth) and $3.1 million (1.3 million Dth), respectively. The fair value of open positions for non-trading purposes at December 31, 1998, as well as the effect of these activities on the Company's results of operations for the same period ending, was not material.

The fair value of futures and forward contracts are determined using quoted market prices or broker's quotes.

The Company's investments in debt and equity securities consist of trust funds for the purpose of funding the nuclear decommissioning of Unit 1 and its share of Unit 2 (see Note 3 - "Nuclear Plant Decommissioning"), investments held by Opinac North America, Inc. and a trust fund for certain pension benefits. The Company has classified all investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1998. The proceeds from the sale of investments were $202.1 million, $159.7 million, and $99.4 million in 1998, 1997, and 1996, respectively. Net realized and unrealized gains and losses related to the nuclear decommissioning trust are reflected in "Accumulated depreciation and amortization" on the Consolidated Balance Sheets, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The unrealized gains and losses related to the investments held by the pension trust and Opinac North America, Inc. for the period ending December 31, 1998 are not material to the results of operations of the Company. The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

	In thousands of dollars							
At December 31,	1998				1997			
		Gross Unrealized				Gross Unrealized		
Security Type	Cost	Gain	(Loss)	Fair Value	Cost	Gain	(Loss)	Fair Value
U.S. Government Obligations	$ 19,291	$ 2,621	$ (117)	$ 21,795	$ 14,136	$ 1,864	$ (4)	$ 15,996
Commercial Paper	82,930	1,269	—	84,199	106,035	1,542	—	107,577
Tax Exempt Obligations.........	104,538	6,786	(164)	111,160	80,115	5,884	(55)	85,944
Corporate Obligations	100,736	22,684	(2,856)	120,564	92,949	17,368	(830)	109,487
Other	6,666	—	—	6,666	3,025	—	—	3,025
	$ 314,161	$ 33,360	$ (3,137)	$ 344,384	$296,260	$26,658	$(889)	$322,029

Using the specific identification method to determine cost, the gross realized gains and gross realized losses were:

	In thousands of dollars		
Year Ended December 31,	1998	1997	1996
Realized gains	$5,350	$3,487	$2,121
Realized losses	2,221	686	806

The contractual maturities of the Company's investments in debt securities is as follows:

	In thousands of dollars	
At December 31, 1998	Fair Value	Cost
Less than 1 year	$ 78,438	$ 77,135
1 year to 5 years	18,289	17,617
5 years to 10 years	63,504	61,122
Due after 10 years	126,363	120,838

NOTE 11. Segment Information

In 1998, the Company adopted SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." SFAS No. 131 supersedes SFAS No. 14, "Financial Reporting for Segments of a Business Enterprise." Prior years' information has been restated to conform to SFAS No. 131.

The Company is organized between regulated and unregulated activities. The Company is pursuing formation of a holding company in 1999 that would further separate these activities. Within the regulated business, which has 99% of total assets and 96% of total revenues, there are three principal business units: Energy Delivery, Nuclear and Fossil/Hydro. The Company has announced plans to, and expects to, consummate sale of the fossil and hydro assets in 1999. Although there are three identified business units, financial performance and resource allocation are measured and managed at the regulated business level.

The Company's unregulated activities do not meet the reporting thresholds of SFAS No. 131, but comprise a substantial portion of "other" in the accompanying table.

In thousands of dollars	Total Revenues	Depreciation & Amortization*	Federal & Foreign Income Taxes	Economic Value Added	Construction Expenditures	Identifiable Assets
1998						
Regulated company	**$3,826,373**	**$ 484,250**	**$ (63,131)**	**$ (697,948)**	**$ 392,200**	**$13,733,055**
Other	**141,931**	**493**	**(3,597)**	**(31,471)**	**—**	**128,132**
Reclassification in consolidation	**(141,931)**	**(493)**	**—**	**—**	**—**	**—**
Total Consolidated	**3,826,373**	**484,250**	**(66,728)**	**(729,419)**	**392,200**	**13,861,187**
1997						
Regulated company	3,966,404	339,641	125,401	(650,188)	290,757	9,431,763
Other	116,258	551	1,194	(32,009)	—	152,378
Reclassification in consolidation	(116,258)	(551)	—	—	—	—
Total Consolidated	3,966,404	339,641	126,595	(682,197)	290,757	9,584,141
1996						
Regulated company	3,975,410	329,253	99,795	(637,444)	352,049	9,290,711
Other	37,595	688	2,699	(21,523)	—	136,924
Reclassification in consolidation	(22,352)	(114)	—	—	—	—
Total Consolidated	$3,990,653	$ 329,827	$102,494	$ (658,967)	$ 352,049	$9,427,635

* Includes amortization of the MRA regulatory asset in 1998.

A reconciliation of total segment Economic Value Added to total consolidated net income for the years ended December 31, 1998, 1997 and 1996 is as follows:

	In thousands of dollars		
	1998	1997	1996
Economic Value Added:			
Operations	$(248,624)	$ (266,459)	$ (230,613)
IPP-Related	(480,795)	(415,738)	(428,354)
Total Economic Value Added	(729,419)	(682,197)	(658,967)
Charge for Use of Investor's Capital	1,225,437	1,237,499	1,244,579
Adjustments for Significant Items	(351,388)	(189,938)	(224,756)
Interest Charges (net of taxes)	(265,455)	(182,029)	(183,102)
Extraordinary Item	—	—	(67,364)
Consolidated Net Income (loss)	$(120,825)	$ 183,335	$ 110,390

The Company implemented a shareholder value based management system. The metric used to measure shareholder value creation is Economic Value Added ("EVA"). EVA is the financial measure used to evaluate projects, allocate resources and report and incent performance.

EVA is calculated as Net Operating Profit after Taxes less a charge for the use of capital employed. The capital charge is determined by applying a rate representing an estimate of investors' expected return given the risk of the business and a targeted capital structure. The rate is not the same as the embedded cost of capital, including the return of equity, that may be established in a rate proceeding. Certain adjustments to accounting data are made to more closely reflect operating or economic results. In each of the three years, an adjustment is made to include the recognition of the off-balance sheet liability for remaining future over-market contracts with IPPs and the corresponding recognition of imputed interest on that liability. In addition, there was a significant adjustment in 1998 to reflect the re-capitalization for EVA purposes of the *PowerChoice* charge and the incremental operating expense associated with the January 1998 ice storm and the September 1998 windstorm.

EVA is further segmented between EVA from Operations and EVA due to the MRA and the remaining over-market IPP contracts. This distinction is used to allow management to focus on operating performance versus shareholder value created as the MRA is amortized, the corresponding debt is retired and remaining contracts are restructured or otherwise expire.

NOTE 12. Stock Based Compensation

Under the Company's stock compensation plans, stock units and stock appreciation rights ("SARs") may be granted to officers, key employees and directors. In addition, the Company's plans allow for the grant of stock options to officers. The table below sets forth the activity under the Company's stock compensation plans for the years 1996 through 1998:

	SARs	Units	Options
Outstanding at December 31, 1995	414,000	169,500	300,583
Granted	376,600	291,228	—
Exercised	—	—	—
Forfeited	—	—	(2,000)
Outstanding at December 31, 1996	790,600	460,728	298,583
Granted	296,300	208,750	—
Exercised	—	(2,514)	—
Forfeited	—	—	—
Outstanding at December 31, 1997	1,086,900	666,964	298,583
Granted	1,723,500	488,428	—
Exercised	(42,700)	(211,403)	—
Forfeited	(28,000)	(10,550)	(12,000)
Outstanding at December 31, 1998	2,739,700	933,439	286,583

Stock units are payable in cash at the end of a defined vesting period, determined at the date of the grant, based upon the Company's stock price for a defined period. SARs become exercisable, as determined at the grant date, and are payable in cash based upon the increase in the Company's stock price from a specified level. As such, for these awards, compensation expense is recognized over the vesting period of the award based upon changes in the Company's stock price for that period. Options were granted over the period 1992 to 1995 and become exercisable in three years and expire ten years from the grant date. These options are all considered to be antidilutive for EPS calculations. Included in the results of operations for the years ending 1998, 1997 and 1996, is approximately $9.8 million, $3.2 million and $2.6 million, respectively, related to these plans.

As permitted by SFAS No. 123 - "Accounting for Stock-Based Compensation" ("SFAS No. 123") the Company has elected to follow Accounting Principles Board Opinion No. 25-"Accounting for Stock Issued to Employees" (APB No. 25) and related interpretations in accounting for its employee stock options. Under APB No. 25, no compensation expense is recognized for stock options because the exercise price of the Company's employee stock options equals the market price of the underlying stock on the grant date. Since stock units and SARs are payable in cash, the accounting under APB No. 25 and SFAS No. 123 is the same. Therefore, the pro forma disclosure of information regarding net income, as required by SFAS No. 123, relates only to the Company's outstanding stock options, the effect of which is immaterial to the financial statements for the years ended 1998, 1997 and 1996. There is no effect on earnings per share for these years resulting from the pro-forma adjustments to net income.

NOTE 13. Quarterly Financial Data (Unaudited)

Operating revenues, operating income (loss), net income (loss) and earnings (loss) per common share by quarters from 1998, 1997 and 1996, respectively, are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The Company's quarterly results of operations reflect the seasonal nature of its business, with peak electric loads in summer and winter periods. Gas sales peak in the winter.

Quarter Ended	In thousands of dollars			
	Operating revenues	Operating Income (loss)	Net Income (loss)	Basic and Diluted Earnings (loss) per common share
December 31, 1998	$ 886,432	$103,263	$ (17,433)	($0.14)
1997	960,304	86,024	7,881	(0.01)
1996	971,106	117,832	(25,808)	(0.24)
September 30, 1998	$ 930,631	$110,287	$ 17,653	$0.05
1997	896,570	110,174	31,683	0.15
1996	895,713	47,119	(12,916)	(0.16)
June 30, 1998	$ 910,906	$(180,824)	$(141,408)	($1.04)
1997	945,698	130,704	40,749	0.22
1996	960,771	142,755	52,992	0.30
March 31, 1998	$1,098,404	$134,297	$ 20,363	$0.08
1997	1,163,832	231,937	103,022	0.65
1996	1,163,063	214,632	96,122	0.60

In the first quarter of 1998, the Company expensed $70.2 million associated with the January 1998 ice storm (of which $62.9 million was considered incremental) or 28 cents per common share. In the second quarter of 1998, the Company recorded a non-cash write-off of $263.2 million ($1.18 per common share) associated with the portion of the MRA disallowed in rates by the PSC. In the fourth quarter of 1996, the Company recorded an extraordinary item for the discontinuance of regulatory accounting principles of $103.6 million (47 cents per common share). In the third quarter of 1996, the Company increased the allowance for doubtful accounts by $68.5 million (31 cents per common share).

Regulated Electric Statistics

	1998	1997	1996
Regulated Electric sales *(Millions of KWh)*:			
Residential	9,643	9,905	10,109
Commercial	11,560	11,552	11,564
Industrial	6,843	7,191	7,148
Industrial – Special	4,568	4,507	4,326
Other	241	235	246
Other electric systems	3,577	3,746	5,431
Subsidiary	—	—	303
	36,432	37,136	39,127
Regulated Electric revenues *(Thousands of dollars)*:			
Residential	$1,201,697	$1,227,245	$1,252,165
Commercial	1,220,067	1,233,417	1,237,385
Industrial	480,942	531,164	524,858
Industrial – Special	63,870	61,820	58,444
Other	55,119	54,545	53,795
Other electric systems	94,756	83,794	113,391
Miscellaneous	144,693	117,456	53,698
Subsidiary	—	—	15,243
	$3,261,144	$3,309,441	$3,308,979
Regulated Electric customers *(Average)*:			
Residential	1,401,178	1,404,345	1,405,083
Commercial	146,034	146,039	145,149
Industrial	1,905	1,970	2,045
Industrial – Special	109	85	99
Other	1,544	1,519	1,302
Subsidiary	—	—	13,557
	1,550,770	1,553,958	1,567,235
Residential *(Average)*:			
Annual KWh use per customer	6,882	7,053	7,195
Cost to customer per KWh	12.46¢	12.39¢	12.39¢
Annual revenue per customer	$857.63	$873.89	$891.17

ELECTRIC CAPABILITY

	Thousands of KW			
December 31,	1998	%	1997	1996
Owned:				
Coal	1,360	17.5	1,360	1,333
Oil*	850	11.0	—	—
Dual Fuel — Oil/Gas	1,346	17.4	1,346	1,336
Nuclear	1,082	14.0	1,082	1,082
Hydro	661	8.5	661	617
	5,299	68.4	4,449	4,368
Purchased:				
New York Power Authority				
— Hydro	1,325	17.1	1,325	1,310
— Nuclear	—	—	—	110
IPPs**	1,125	14.5	2,382	2,406
	2,450	31.6	3,707	3,826
Total capability***	7,749	100.0	8,156	8,194
Electric peak load	5,928		6,348	6,021

* In 1994, Oswego Unit No. 5 (an oil-fired unit with a capability of potentially up to 850,000 KW) was put into long-term cold standby. In June 1998, the unit was returned to service.

** On June 30, 1998, the MRA was consummated with 14 IPPs. The MRA allowed the Company to terminate, restate or amend 27 PPAs. The Company terminated 18 PPAs for 1,092 MW of electric generating capacity, restated eight PPAs representing 535 MW of capacity and amended one PPA representing 42 MW of capacity.

*** Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems.

Regulated Gas Statistics

	1998	1997	1996
Regulated Gas sales *(Thousands of Dth)*:			
Residential	47,250	55,203	56,728
Commercial	17,023	22,069	25,353
Industrial	752	1,381	2,770
Total sales	65,025	78,653	84,851
Other gas systems	17	28	30
Spot market	4,501	2,451	10,459
Transportation of customer-owned gas	127,850	152,813	134,671
Total gas delivered	197,393	233,945	230,011
Regulated Gas revenues *(Thousands of dollars)*:			
Residential	$378,150	$436,136	$417,348
Commercial	110,499	148,213	162,275
Industrial	3,618	6,549	13,325
Other gas systems	69	130	138
Spot market	8,749	6,346	37,124
Transportation of customer-owned gas	54,091	55,657	50,381
Miscellaneous	10,053	3,932	1,083
	$565,229	$656,963	$681,674
Regulated Gas customers *(Average)*:			
Residential	487,325	484,862	477,786
Commercial	39,779	40,955	41,266
Industrial	168	186	206
Other	6	6	6
Transportation	3,355	2,557	713
	530,633	528,566	519,977
Residential *(Average)*:			
Annual dekatherm use per customer	97.0	113.9	118.7
Cost to customer per Dth	$8.00	$7.90	$7.36
Annual revenue per customer	$775.97	$899.51	$873.50
Maximum day gas sendout (Dth)	1,083,802	1,133,370	1,152,996

Corporate Information

Annual Meeting
The Annual Meeting of Shareholders will be held at the Saratoga Springs City Center, 522 Broadway, Saratoga Springs, NY, at 10:30 a.m., Tuesday, May 18, 1999. A notice of the meeting, proxy statement and form of proxy will be sent in March to holders of common stock.

SEC Form 10-K Report
A copy of the company's Form 10-K report, filed annually with the Securities and Exchange Commission, is available without charge by writing the Investor Relations Department at 300 Erie Boulevard West, Syracuse, NY 13202.

Shareholder Inquiries
Questions regarding shareholder accounts may be directed to the company's Shareholder Services Department:

315-428-6750
(Syracuse)

800-448-5450
(elsewhere in the continental U.S.)

Analyst Inquiries
Analyst inquiries should be directed to:
Leon T. Mazur, Director-Investor Relations,
Phone: 315-428-5876, email: mazurl@nimo.com

Stock Exchange Listings
Ticker Symbol: NMK
Common stock and most preferred series are listed and traded on the New York Stock Exchange.
Bonds are traded on the New York Stock Exchange.

Disbursing Agent

Common and preferred stocks:
Niagara Mohawk Power Corp.
300 Erie Boulevard West
Syracuse, NY 13202

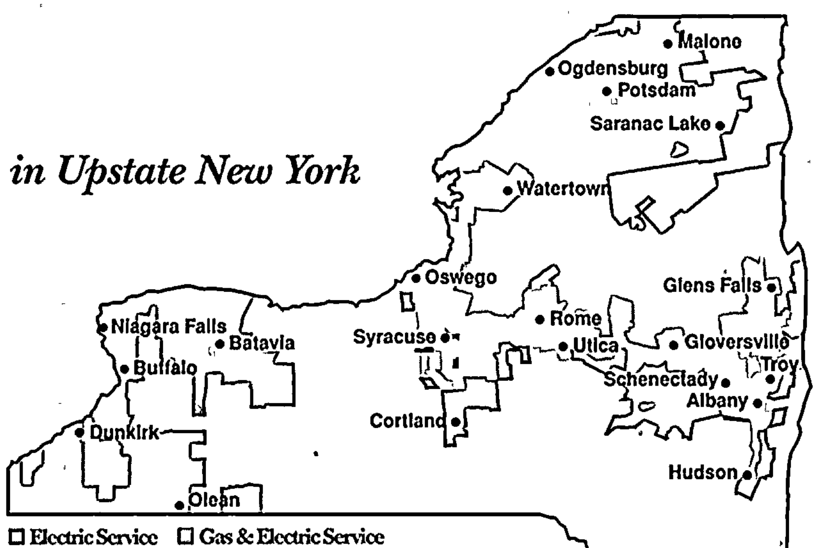
Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, NY 10015

Transfer Agent and Registrars

Common and preferred stocks:
The Bank of New York
P.O. Box 11002
Church Street Station
New York, NY 10286
800-524-4458

Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, NY 10015

Serving Our Customers in Upstate New York



Niagara Mohawk Power Corp. is an investor-owned utility providing energy to the largest customer service area in New York.

Our electric system meets the needs of more than 1.5 million residential, commercial, and industrial customers. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

Our natural gas system provides service to more than 500,000 residential and business customers on a retail basis, as well as a growing number of customers for whom we transport gas that they purchase directly from suppliers.

The 1998 Annual Report is submitted for shareholders' information. It is not intended for use in connection with any sale or offer to sell or buy any securities.

Printed on recycled paper

This report was produced by Niagara Mohawk employees.

Directors

Salvatore H. Alfiero (B, E)
Chairman and Chief Executive Officer
Mark IV Industries, Inc., Amherst, NY

William F. Allyn (A, C, F)
President and Chief Executive Officer
Welch Allyn, Inc., Skaneateles Falls, NY

Albert J. Budney, Jr.
President

Lawrence Burkhardt, III (F)
Former Executive Vice President
Nuclear Operations, San Diego, CA

Douglas M. Costle (A, B, D, F)
Distinguished Senior Fellow and Chairman of the Board, Institute for Sustainable Communities, Montpelier, VT

William E. Davis (D)
Chairman of the Board and
Chief Executive Officer

William J. Donlon
Former Chairman of the Board and
Chief Executive Officer, Syracuse, NY

Anthony H. Gioia (C, D, F)
Chairman of the Board and
Chief Executive Officer
Gioia Management, Inc., Buffalo, NY

Dr. Bonnie G. Hill (A, B, E)
President and Chief Executive Officer
The Times Mirror Foundation
Los Angeles, CA

Clark A. Johnson (C, E)
Former Chairman
Pier 1 Imports, Inc., Fort Worth, TX

Henry A. Panasci, Jr. (B, C, E)
Chairman
Cygnus Management Group, LLC
Syracuse, NY

Dr. Patti McGill Peterson (A, B, D)
Executive Director
Council for International Exchange
of Scholars, Washington, DC

Donald B. Riefler (A, D, E, F)
Financial Market Consultant
Vero Beach, FL

Stephen B. Schwartz (C, D, E)
Former IBM Senior Vice President
Palm Beach Gardens, FL

(Edmund M. Davis retired from the Board effective June 29, 1998.)

A. Audit Committee
B. Committee on Corporate Public Policy and Environmental Affairs
C. Compensation and Succession Committee
D. Executive Committee
E. Finance Committee
F. Nuclear Oversight Committee

Officers

William E. Davis
Chairman of the Board and
Chief Executive Officer

Albert J. Budney, Jr.
President

Darlene D. Kerr
Executive Vice President
Energy Delivery
(Effective September 1, 1998)

David J. Arrington
Senior Vice President
Human Resources

Thomas H. Baron
Senior Vice President
Field Operations
(Effective October 22, 1998)

Edward J. Dienst
Senior Vice President
Customer Delivery and Asset Management
(Effective October 22, 1998)

William F. Edwards
Senior Vice President
and Chief Financial Officer

Gary J. Lavine
Senior Vice President
Legal and Corporate Relations

John H. Mueller
Senior Vice President
and Chief Nuclear Officer

Richard B. Abbott
Vice President
Nuclear Engineering

Joseph T. Ash
Vice President, Gas Delivery

Nicholas J. Ashooh
Vice President, Communications
and Government Relations

Richard R. Borsellino
Vice President
Operations, Construction
and Maintenance
(Effective December 10, 1998)

John T. Conway
Vice President
Nuclear Generation

Kim A. Dahlberg
Vice President
Special Projects, Nuclear

Theresa A. Flaim
Vice President
Corporate Strategic Planning

Michael J. Kelleher
Vice President
Financial Planning

Peter H. Lebro
Vice President
Logistics and Field Services
(Effective December 10, 1998)

Leslie E. LoBaugh, Jr.
Vice President and General Counsel
(Effective February 8, 1999)

Samuel F. Manno
Vice President
Special Projects (Year 2000)

Douglas R. McCuen
Vice President
Government and Regulatory Relations

Clement E. Nadeau
Vice President
Electric Delivery

Kapua A. Rice
Corporate Secretary

Arthur W. Roos
Vice President-Treasurer

Richard H. Ryczek
Vice President
Environmental Affairs and
Property Management

William J. Synwoldt
Vice President
Information Technology and
Chief Information Officer

Steven W. Tasker
Vice President-Controller

Carl D. Terry
Vice President, Nuclear Safety
Assessment and Support

David J. Walsh
Vice President
Employee Relations and Ethics
(Effective October 1, 1998)

Stanley W. Wilczek, Jr.
Vice President
Customer Service

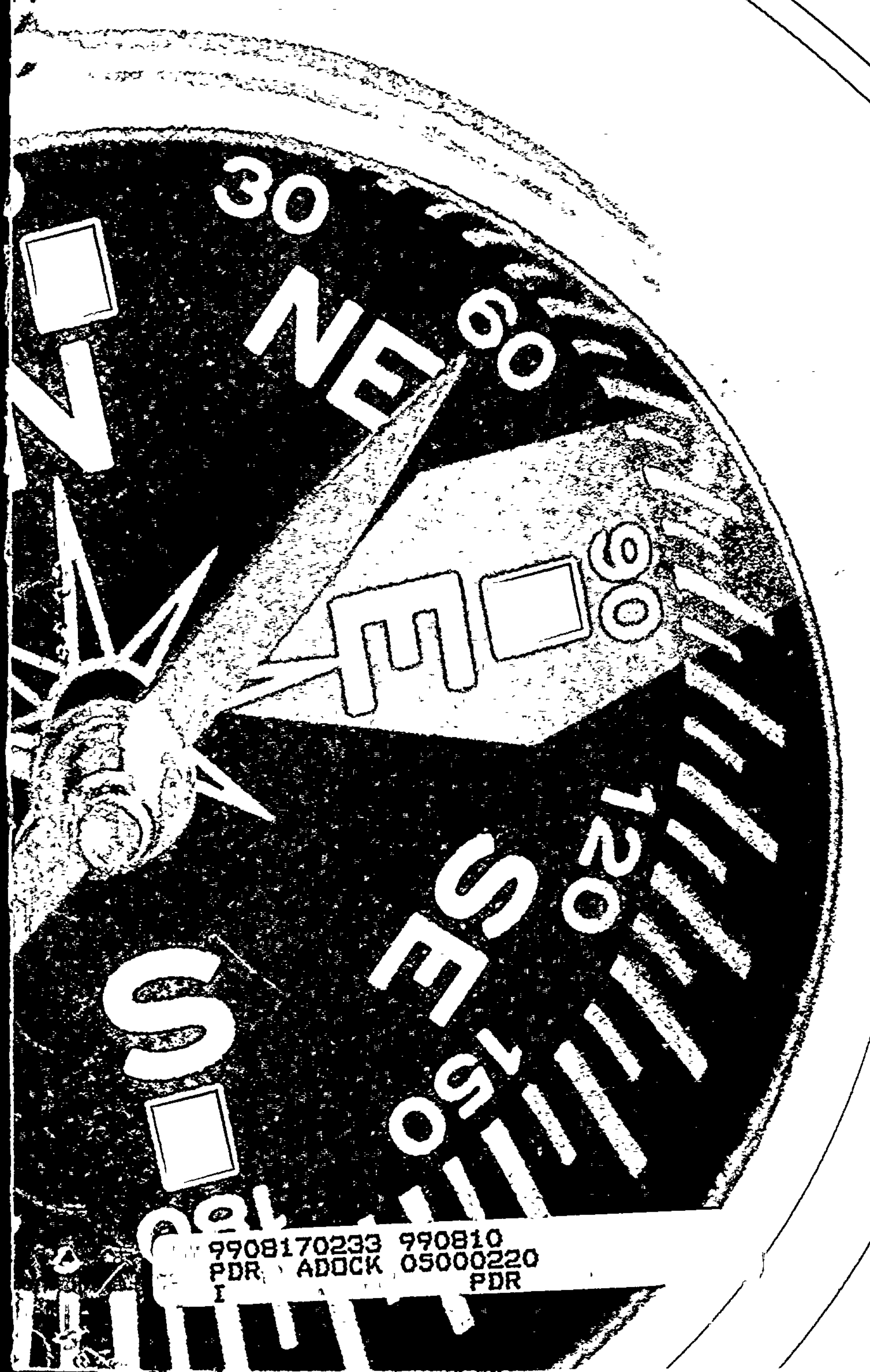
(B. Ralph Sylvia retired as an officer, effective July 1, 1998; Thomas R. Fair and Paul J. Kaleta resigned as officers, effective March 20, 1998 and September 4, 1998, respectively.)

Glossary of Terms

Term	Definition
AFC	Allowance for Funds Used During Construction
CNG	CNG Transmission Corporation, an interstate natural gas pipeline regulated by FERC
CNP	Canadian Niagara Power Company, Limited
COPS	Competitive Opportunities Proceeding
CTC	Competitive transition charges: a mechanism established in the *PowerChoice* agreement to recover stranded costs from customers
DEC	New York State Department of Environmental Conservation
DOE	U. S. Department of Energy
Dth	Dekatherm: one thousand cubic feet of gas with a heat content of 1,000 British Thermal Units per cubic foot
EBITDA	Earnings before Interest Charges, Interest Income, Income Taxes, Depreciation and Amortization, Amortization of Nuclear Fuel, Allowance for Funds Used During Construction, MRA Regulatory Asset amortization, non-cash regulatory deferrals and other amortizations and extraordinary items (a non-GAAP measure of cash flow)
FAC	Fuel Adjustment Clause: a clause in a rate schedule that provides for an adjustment to the customer's bill if the cost of fuel varies from a specified unit cost
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRT	Gross Receipts Tax
GWh	Gigawatt-hour: one gigawatt-hour equals one billion watt-hours
IPP	Independent Power Producer: any person that owns or operates, in whole or in part, one or more Independent Power Facilities
IPP Party	Independent Power Producers that were a party to the MRA
KW	Kilowatt: one thousand watts
KWh	Kilowatt-hour: a unit of electrical energy equal to one kilowatt of power supplied or taken from an electric circuit steadily for one hour
MRA	Master Restructuring Agreement - an agreement, including amendments thereto, which terminated, restated or amended certain IPP Party power purchase agreements effective June 30, 1998
MRA regulatory asset	Recoverable costs to terminate, restate or amend IPP Party contracts, which have been deferred and are being amortized and recovered under the *PowerChoice* agreement
MW	Megawatt: one million watts
MWh	Megawatt-hour: one thousand kilowatt-hours
Net Cash Interest	Reflects interest charges plus allowance for funds used during construction less the non-cash impact of the net amortization of discount on long-term debt and interest accrued on the Nuclear Waste Policy Act disposal liability less interest income
NRC	U. S. Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool
NYPP Member Systems	Eight Member Systems are: the seven New York State investor-owned electric utilities and NYPA
NYSERDA	New York State Energy Research and Development Authority
PowerChoice agreement	Company's five-year electric rate agreement, which incorporates the MRA, approved by the PSC in an order dated March 20, 1998
PPA	Power Purchase Agreement: long-term contracts under which a utility is obligated to purchase electricity from an IPP at specified rates
PRP	Potentially Responsible Party
PSC	New York State Public Service Commission
PURPA	Public Utility Regulatory Policies Act of 1978, as amended. One of five bills signed into law on November 8, 1978, as the National Energy Act. It sets forth procedures and requirements applicable to state utility commissions, electric and natural gas utilities and certain federal regulatory agencies. A major aspect of this law is the mandatory purchase obligation from qualifying facilities.
QF	Qualifying Facility: an individual (or corporation) that owns and/or operates a generating facility but is not primarily engaged in the generation or sale of electric power. QFs are either power production or cogeneration facilities that qualify under Section 201 of PURPA.
ROE	Return on Common Stockholders Equity
SFAS No. 71	Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 101	Statement of Financial Accounting Standards No. 101 "Regulated Enterprises - Accounting for the Discontinuance of Application of FASB Statement No. 71"
SFAS No. 106	Statement of Financial Accounting Standards No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes"
SFAS No. 121	Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of"
Stranded costs	Utility costs that may become unrecoverable due to a change in the regulatory environment
Unit 1	Nine Mile Point Nuclear Station Unit No. 1
Unit 2	Nine Mile Point Nuclear Station Unit No. 2

1998 Annual Report

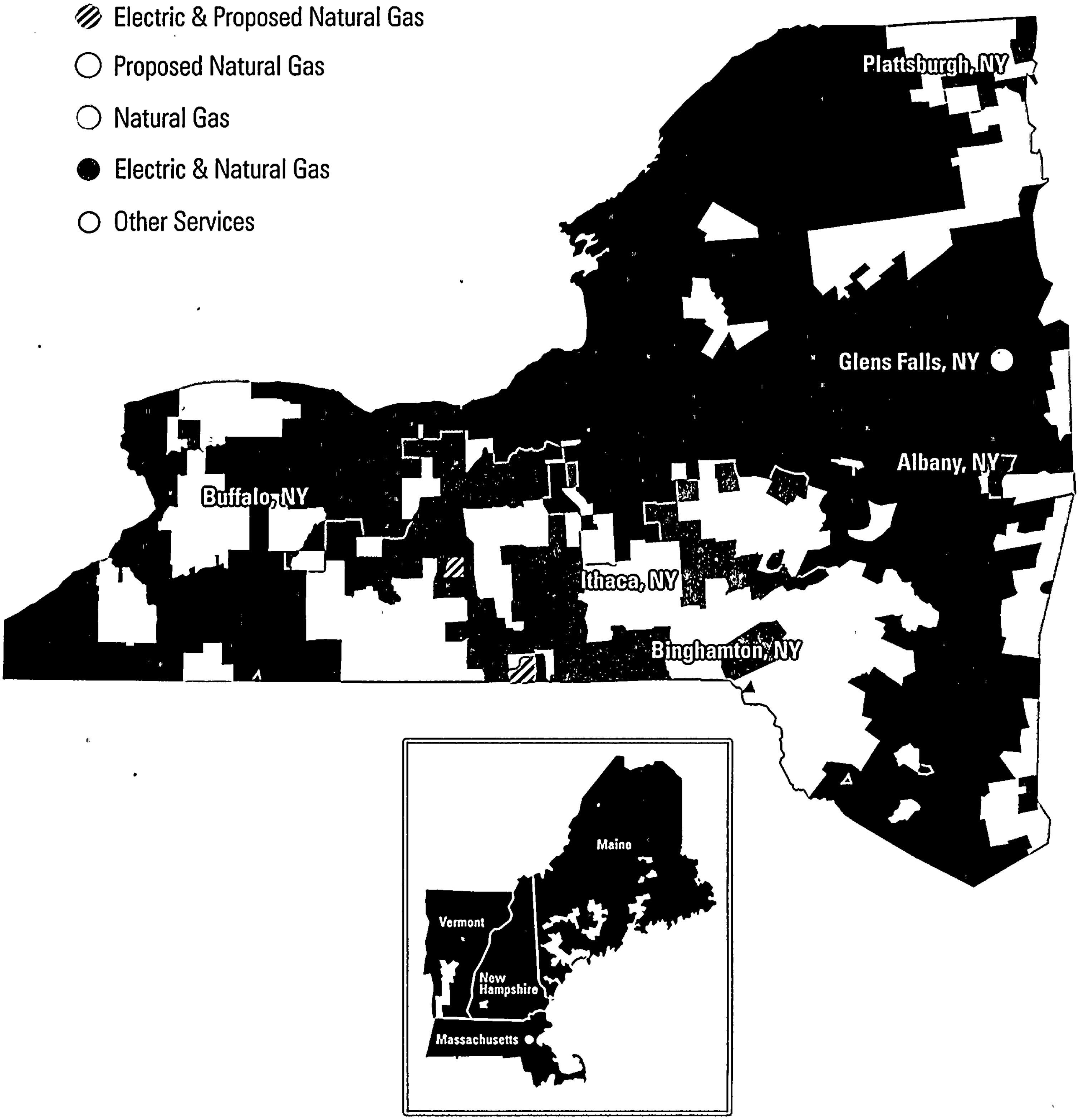
Docket # 50-220
Accession # 9908170233
Date 8/10/99 of Ltr
Regulatory Docket File



Energy East

Energy East Corporation At a Glance

- ○ Electric
- Electric & Proposed Natural Gas
- ○ Proposed Natural Gas
- ○ Natural Gas
- ● Electric & Natural Gas
- ○ Other Services



Energy East Corporate Profile

Overview

Energy East Corporation (NYSE: NEG) is an energy delivery, products and services company with operations in New York, Massachusetts, Maine, New Hampshire, Vermont and New Jersey. We deliver electricity and natural gas to retail customers and provide electricity, natural gas and energy management and other services to retail and wholesale customers in the Northeast. We are at the forefront of the restructuring of the energy market.

Lines of Business

NYSEG supplies, markets and delivers electricity to 817,000 customers and natural gas to 243,000 customers across more than one-third of New York State.

NGE Generation generates electricity from seven coal-fired stations.

Energy East Enterprises:

CMP Natural Gas, our joint venture with Central Maine Power, is building a natural gas distribution system to serve most of.the populated areas outside of the greater Portland area.

New Hampshire Gas operates a propane air distribution system in Keene with the goal of bringing natural gas to the Keene area.

Southern Vermont Natural Gas is developing a combined natural gas supply and electric generation project with Iroquois Gas Transmission System and Vermont Energy Park Holdings.

XENERGY Enterprises:

XENERGY provides energy services, information systems and energy consulting on a national basis.

Energy East Solutions sells electricity and natural gas to end-use customers and wholesale markets in the Northeast, markets retail electricity and energy management services in the mid-Atlantic region through an alliance with South Jersey Energy, and consolidates energy use information and produces energy bills and reports for large, multi-site businesses.

Cayuga Energy will own and operate electric generating stations that sell electricity to the wholesale market during periods of high electricity demand.

Energy East Telecommunications is building a fiber optic communications system linking Binghamton, Ithaca and Syracuse, New York, in a joint venture with Telergy, a Syracuse, New York-based firm.

Energy East

Dear Shareholder:

1998 was a major transitional year for your company. It was a crucial dividing line between what was and what will be. We are moving from a vertically integrated upstate New York utility to a growing energy distribution and services company in the Northeast. We are now better positioned to grow and meet the challenges of an emerging competitive market. And we are committed to achieving "best in class" operations and continued growth in value for you, our shareholders.

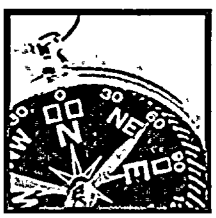
Earnings Per Share

During 1998 we took major steps in refocusing our business on energy distribution. First, and most important, we accepted offers above book value for the sale of our coal-fired generation assets. Generation has been a cornerstone of NYSEG for our entire existence. This was a very difficult decision to make, but we felt we had to take this step if we were going to refocus your company. With this decision, we will no longer face the risk and uncertainty of stranded generation costs. We will use the proceeds to continue to buy back common stock and to focus on new opportunities.

We are considered progressive and a leader in the deregulation of the industry. We capped electricity and natural gas prices in upstate New York through 2002 and are operating without the fuel cost protection that most other utilities have. Since we will no longer have base load generation, we must now secure energy in the sometimes volatile open market. Our natural gas customers have benefited from a competitive market for several years and all of our electric customers will be able to choose their supplier this coming summer.

The steps we have taken and the strategies we have chosen, combined with our proven ability to adapt to the changing energy market, are intended to create a more efficient and more market driven company.

Managing change in an environment where our state regulators are unbundling and dismantling our traditional business in no predetermined order, yet being held accountable to the rules and regulations of the past, is no small challenge for our employees. Our people continue to deliver superior customer service during this period of convulsive change and I thank them for their performance and support. Our customer complaint rate is the lowest among all of the electric and gas utilities and telephone companies in New York State. Customers are especially pleased with the reliability we provide and the results of the direct contacts they have with us.



The traditional side of our business will continue to concentrate on making yesterday's commitments more effective as the transitional business focuses on new opportunities and becomes the business of tomorrow. The tension between the traditional and transitional businesses will remain with us for the future, but I am confident that you can continue to count on us to deliver the value that you and our customers expect.

Following the Annual Meeting of Shareholders in April 1999, Everett A. Gilmour and Alton G. Marshall will be retiring from the Board of Directors. Their contributions during their respective 19 and 28 years of dedicated service to our company are deeply appreciated and I especially want to thank them for the guidance they have given me for the past two years.

I look forward to sharing with you further progress at Energy East.

On behalf of the Board of Directors,

Wes Von Schack

Wesley W. von Schack
Chairman, President and Chief Executive Officer
February 9, 1999

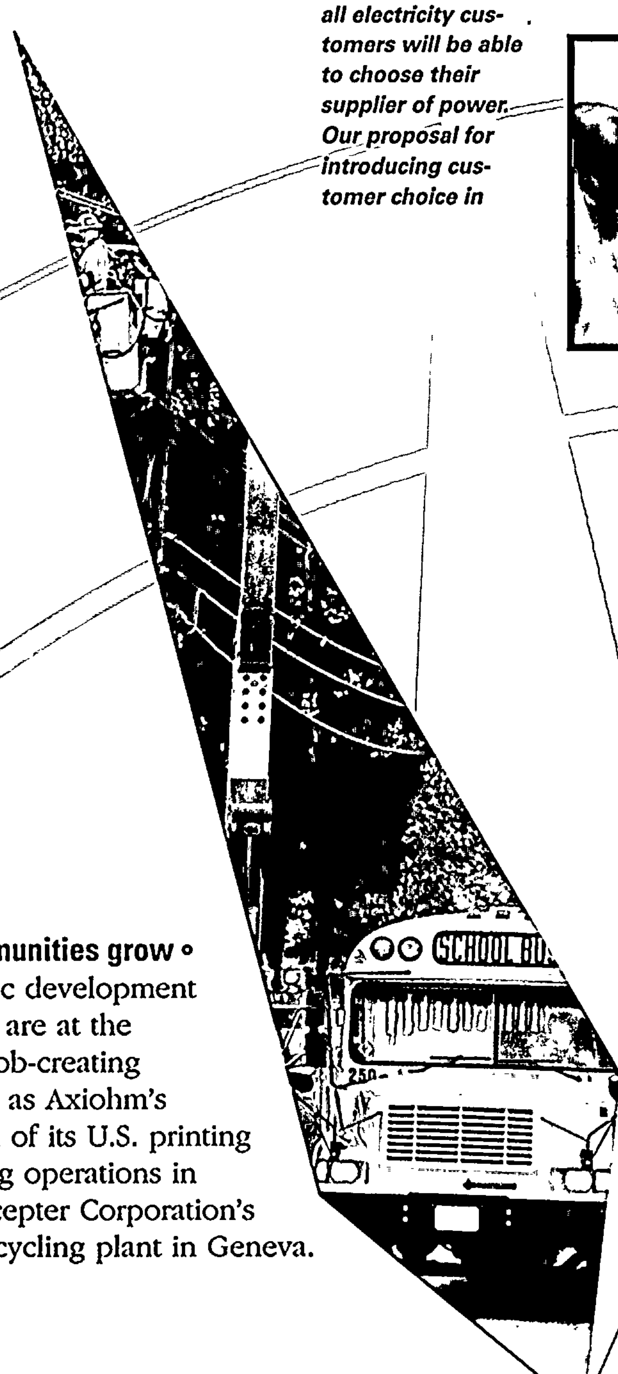
1998 Highlights

The stories and photos on the following pages offer a snapshot of the initiatives Energy East is taking to add to the value of your investment.

Adding to the value of your investment • Our stock price increased 59% during the year while the S&P Utility Average, which comprises 39 electric and natural gas utilities, increased 8%. Earnings increased 18% over 1997. That is on top of an 8% increase in 1997. Our common stock dividend was raised in January 1999 to a new annual rate of \$1.68. Also, the Board of Directors declared a two-for-one stock split on common stock outstanding. Shareholders of record at the close of business on March 12, 1999, will be entitled to the shares on April 1, 1999.

Extraordinary Value

Actively promoting competition • *By August 1, 1999, all electricity customers will be able to choose their supplier of power. Our proposal for introducing customer choice in New York State is one of the most progressive plans in the country.*

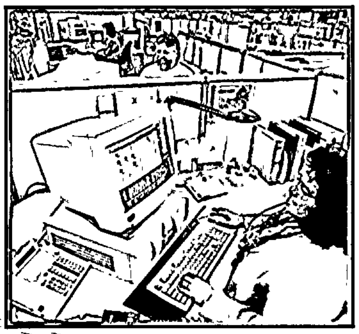


Helping communities grow • Our economic development professionals are at the forefront of job-creating projects such as Axiohm's consolidation of its U.S. printing manufacturing operations in Ithaca and Scepter Corporation's aluminum recycling plant in Geneva.

Fostering competition • *To help encourage competition, we are completing the sale of our coal-fired generating assets to The AES Corporation and Edison Mission Energy. We are also actively pursuing the sale of our 18% stake in the Nine Mile Point nuclear generating unit No. 2.*

Managing costs • Working efficiently and doing more with less are not new to us. Our costs are declining and we expect that to continue. We fund our capital spending completely with internally generated funds.

Delivering superior customer service • *We have an excellent track record for providing superior customer service. We continue to have the lowest rate of customer complaints among all of the electric and natural gas utilities and telephone companies in New York State.*

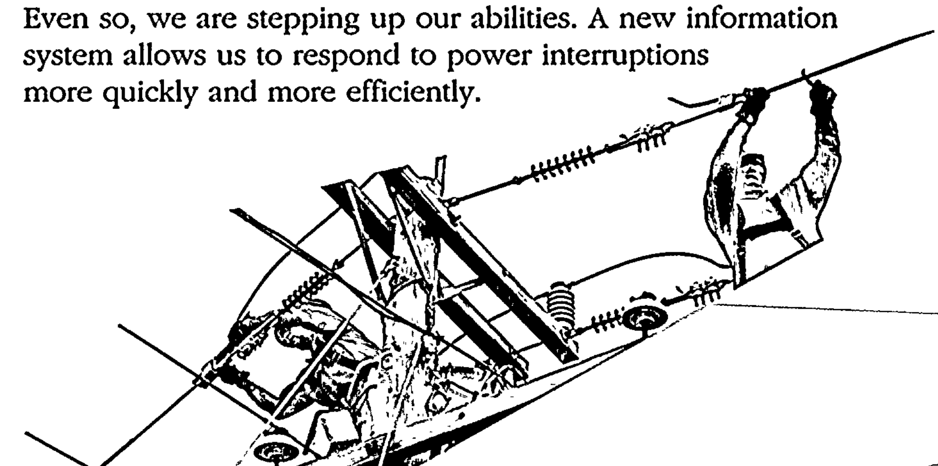


Our customers tell us that we are doing an excellent job when it comes to customer interaction and reliability.

Building strong relationships with our customers ∘ Relationships are about much more than responding to questions about a customer's bill, hooking up a new service on time, or restoring power quickly after an interruption. They are also about helping customers use energy wisely. We teamed up with the City of Norwich, New York to design and install a natural gas-powered engine to pump the city's water. The result: fewer maintenance problems, reduced costs and a satisfied customer. Near Buffalo, our marketing, engineering and construction people joined forces to install a new electric service for a growing business. Our reputation for high quality work and excellent service made our customer's decision to look to us an easy one.

Superior Service

Building on our excellent reputation for service reliability ∘ Even the devastating ice storm that left 30,000 of our customers without power in the Plattsburgh area last January and the tornadoes that ripped through three areas in May were no match for our power restoration team. Customers applauded our efforts and the Public Service Commission called our response to the ice storm "outstanding." Even so, we are stepping up our abilities. A new information system allows us to respond to power interruptions more quickly and more efficiently.

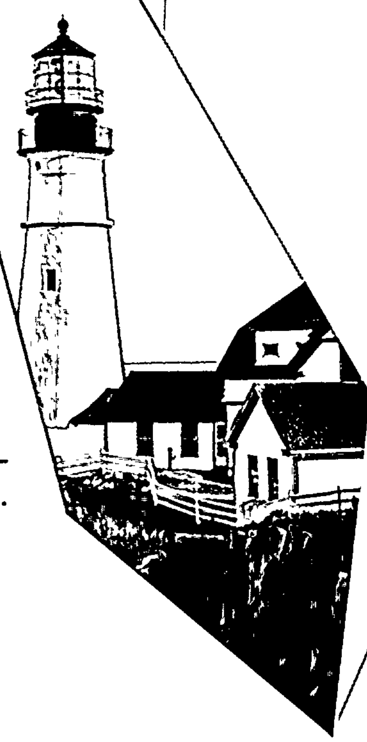


Committing our energy to the communities we serve ∘ We have a long and proud tradition of financially supporting community activities and educational programs. Our people show a strong commitment to their communities by giving their time and energy to deserving organizations, including the American Cancer Society, the American Heart Association, United Way, Rotary Clubs and dozens of community service organizations. This strong ethic of giving back extends to all of our operations and is reflected in our Adopt-a-Highway and Community Watch programs.

***Growing* • The second expansion of one of our newest natural gas franchises in New York is now complete. A food processing plant, two paper mills and a school are now being served in Lewis County, northeast of Syracuse. With our expansion into New England, we continue to be one of the fastest growing natural gas companies in the Northeast, and our prices are among the lowest.**

Linking communities with fiber optics • We are building a fiber optic communications network linking Binghamton, Ithaca and Syracuse in upstate New York in a joint venture with Telergy, a Syracuse, New York-based firm. Internet access and long distance telephone service providers are potential users of the network. This infrastructure will help attract new businesses to the region.

Solid Growth

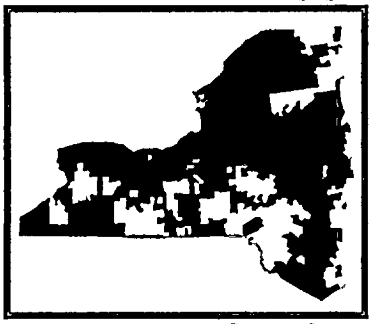


Delivering a new energy option in Maine • Clean, efficient, economical natural gas will soon be at the doorstep of homes and businesses in central and southern Maine. Our joint venture with Central Maine Power will serve most of the populated areas outside of the greater Portland area.

Bringing natural gas to southern Vermont • We are planning a combined natural gas supply and electric generation project in southwestern Vermont with Iroquois Gas Transmission System and Vermont Energy Park Holdings. The project includes an extension of pipeline from New York to Vermont, two combined cycle electric generating plants, and natural gas distribution to industrial, commercial and residential customers.

***Building a presence in New Hampshire* • We have purchased and are operating a propane air distribution system in Keene, New Hampshire. We are encouraged by the economic vitality of the area, and our long-term plans call for bringing natural gas to the Keene area.**

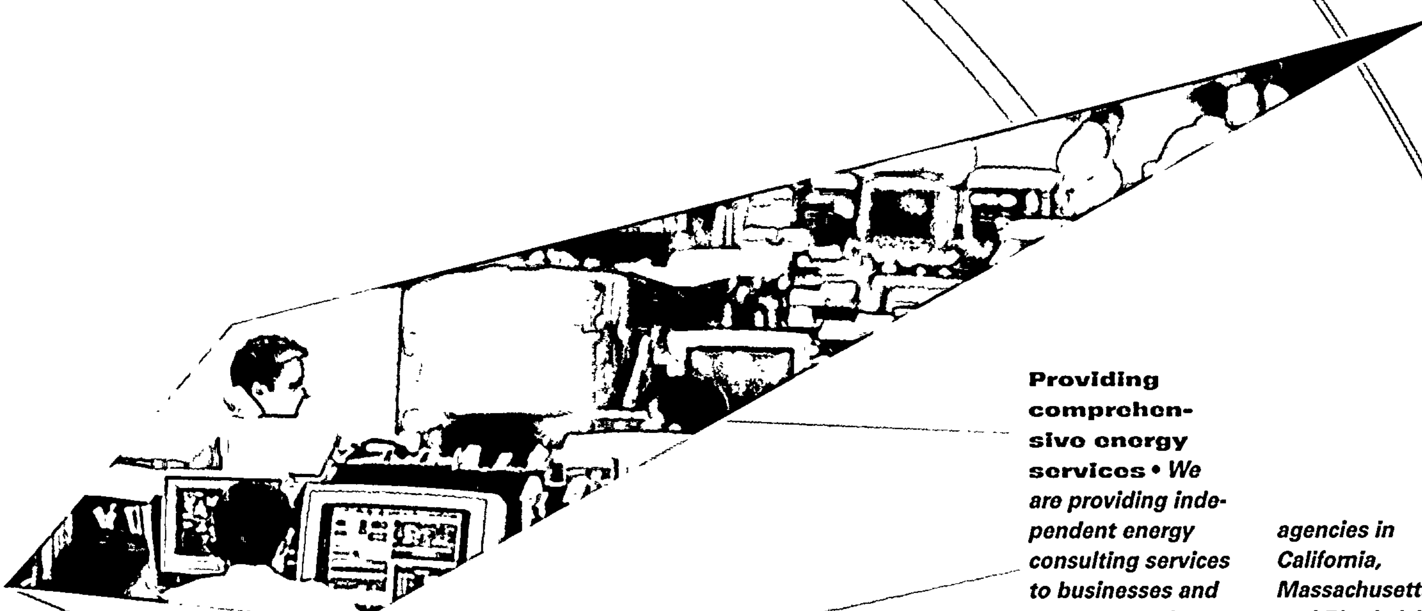
Adapting to a competitive marketplace ∘ Our success in adapting to a competitive environment has enabled us to reduce and cap electricity prices, with no fuel adjustment, through 2002 and deliver an overall reduction in natural gas prices, with no gas adjustment factor, through September 2002. In addition to taking costs out of the business, we have sharpened our focus on performance excellence.



Opening up our system • *By August 1, 1999, all 817,000 of our electricity customers will be able to choose their power supplier. Our largest natural gas customers have had the option of shopping among competitive suppliers for more than 12 years, and since 1996 this option was made available to smaller customers through an aggregation process.*

Market Driven

Helping businesses manage energy use ∘ We continue to develop strong relationships with nationally known businesses to manage their energy use. Among our new customers in 1998 was Pitney Bowes Inc. Our system helps Pitney Bowes manage and control its energy costs while gathering, consolidating and reporting energy use information.

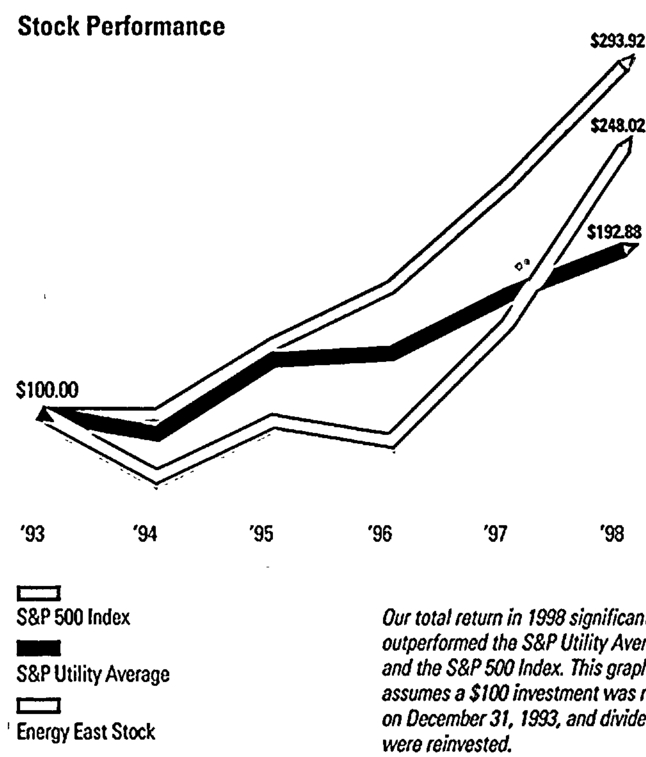


Providing comprehensive energy services • *We are providing independent energy consulting services to businesses and governmental agencies in California, Massachusetts and Rhode Island, the first states to restructure their electricity markets. We are also a leading buyer's agent as a result of our success in two of the largest customer aggregation programs in the country.*

Succeeding in an evolving energy market ∘ We are vying for the business of consumers in the Northeast who are already able to choose their electricity and natural gas suppliers. In addition, we have joined forces with South Jersey Energy to market energy services and electricity to end-use customers in the mid-Atlantic region. The alliance leverages South Jersey Energy's market presence and customer relationship and our trading and retail sales expertise.

FINANCIAL HIGHLIGHTS

Per Common Share	1998	1997	% Change
Common Stock Price at Year End	$56.50	$35.50	59
Earnings	$3.02	$2.57	18
Dividends Paid	$1.55	$1.40	11
Book Value at Year End	$27.22	$26.71	2
Other Common Stock Information			
Return on Average Common Equity	11.2%	9.8%	14
Average Common Shares Outstanding (Thousands)	64,371	68,153	(6)
Common Shares Outstanding at Year End (Thousands)	62,947	67,508	(7)
Operating Results (Thousands)			
Total Operating Revenues	$2,499,418	$2,170,102	15
Total Operating Expenses	$2,024,579	$1,733,141	17
Net Income	$194,205	$175,211	11
Retail Deliveries (Megawatt-hours)	13,277	13,238	–
Wholesale Deliveries (Megawatt-hours)	22,711	10,406	118
Retail Deliveries (Dekatherms)	54,162	59,324	(9)
Wholesale Deliveries (Dekatherms)	7,527	3,027	149
Total Assets at Year End (Thousands)	$4,883,337	$5,028,681	(3)



Our total return in 1998 significantly outperformed the S&P Utility Average and the S&P 500 Index. This graph assumes a $100 investment was made on December 31, 1993, and dividends were reinvested.

Energy East

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

Shareholder Information

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

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

Please contact Shareholder Services with questions regarding:

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

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

Transfer Agent and Registrar • ChaseMellon Shareholder Services

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

ChaseMellon Shareholder Services
P.O. Box 3312
South Hackensack, NJ 07606-1912

To request transfer instructions, write to:

ChaseMellon Shareholder 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 Office Addresses • P.O. Box 12904, Albany, NY 12212-2904
P.O. Box 1196, Stamford, CT 06904-1196

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 at the telephone number or address listed above.

Trading Symbol • NEG is the trading symbol for Energy East Corporation common stock listed on the New York Stock Exchange.

Annual Meeting • The annual meeting of shareholders will be held at 10:30 a.m. on April 23, 1999.

Board of Directors

Richard Aurelio •a director since 1997, is a director of the Citizens Committee for New York City, Inc. and the Javits Foundation, both 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 a trustee of Dr. G. Clifford & Florence B. Decker Foundation, 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 Blue Cross & Blue Shield of Western New York, both in Buffalo, New York.

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

Everett A. Gilmour •a director since 1980, is Chairman of the Board of The National Bank and Trust Company of Norwich and N.B.T. Bancorp, Inc., both in Norwich, New York.

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

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

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

Alton G. Marshall •a director since 1971, is President of Alton G. Marshall Associates, Inc., a real estate investment company in New York, New York.

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 and Chief Executive Officer of the corporation.

Committees •(Chairperson listed first)
Audit: Lynch, DeFleur, Gioia, Rich
Executive Compensation and Succession: Gilmour, Aurelio, Castiglia, Marshall
Nominating: Marshall, Aurelio, DeFleur, Gilmour
NYSEG's Corporate Responsibility: Carrigg, Casarett, Keeler, Rich

Executive Officers

ENERGY EAST CORPORATION

Wesley W. von Schack • Chairman, President and Chief Executive Officer
Michael I. German • Senior Vice President
Kenneth M. Jasinski • Senior Vice President and General Counsel
Robert D. Kump • Treasurer
Robert E. Rude • Controller
Daniel W. Farley • Secretary

Electric Generation Statistics

	1998	1997	1996	1995	1994	1993
System Capability (Megawatts)						
Coal	2,286	2,277	2,236	2,226	2,278	2,394
Nuclear	205	207	206	206	189	189
Hydro	59	66	62	61	69	67
Internal combustion	7	7	7	7	7	7
Total Generating Capability	2,557	2,557	2,511	2,500	2,543	2,657
Purchased Power						
New York Power Authority	641	594	591	517	514	486
NUGs	565	551	599	595	594	362
Less: Firm sales	(527)	(625)	(607)	(118)	(367)	(311)
Total System Capability	3,236	3,077	3,094	3,494	3,284	3,194
System Capability (Percent)						
Coal	71	74	72	63	69	75
Nuclear	6	7	7	6	6	6
Hydro	2	2	2	2	2	2
Total Generating Capability	79	83	81	71	77	83
Purchased Power						
New York Power Authority	20	19	19	15	16	15
NUGs	17	18	20	17	18	12
Less: Firm sales	(16)	(20)	(20)	(3)	(11)	(10)
Total System Capability	100	100	100	100	100	100
Megawatt-Hour Production, Net (Thousands)						
Generated						
Coal	16,146	14,985	14,195	14,296	14,338	15,131
Nuclear	1,315	1,598	1,566	1,306	1,509	1,295
Hydro	317	313	309	240	321	309
Total Generated	17,778	16,896	16,070	15,842	16,168	16,735
Purchased Power						
New York Power Authority	2,006	1,957	1,921	1,849	1,700	1,617
NUGs	4,016	4,051	4,235	4,413	3,601	2,472
Other, net	13,548	2,199	465	155	14	78
Total	37,348	25,103	22,691	22,259	21,483	20,902
Production Expenses (Thousands)						
Generated	$330,590	$327,042	$322,233	$335,706	$339,546	$371,891
Purchased Power						
New York Power Authority	32,253	27,923	27,263	26,079	21,478	16,713
NUGs	326,008	323,959	319,958	283,913	214,010	137,791
Other	394,717	58,001	13,532	8,448	6,864	7,463
Total	$1,083,568	$736,925	$682,986	$654,146	$581,898	$533,858

Note: We accepted offers from The AES Corporation and Edison Mission Energy in August 1998 for the purchase of our seven coal-fired stations and associated assets and liabilities. The sales are expected to close by the end of the first quarter of 1999.

ELECTRIC AND NATURAL GAS DELIVERIES STATISTICS

	1998	1997	1996	1995	1994	1993
(Thousands)						
Electric Deliveries						
(Megawatt-hours)						
Residential	**5,143**	5,267	5,393	5,286	5,399	5,423
Commercial	**3,393**	3,495	3,430	3,405	3,315	3,298
Industrial	**3,118**	3,065	2,992	3,010	2,997	2,950
Other	**1,623**	1,411	1,401	1,392	1,437	1,417
Total Retail	**13,277**	13,238	13,216	13,093	13,148	13,088
Wholesale	**22,711**	10,406	7,914	7,636	6,827	6,233
Total Electric Deliveries	**35,988**	23,644	21,130	20,729	19,975	19,321
Electric Revenues						
Residential	**$715,705**	$728,776	$744,439	$725,299	$679,124	$635,155
Commercial	**391,224**	403,480	400,841	395,076	366,854	333,674
Industrial	**239,455**	243,850	242,792	247,576	245,218	228,215
Other	**172,823**	157,537	158,377	158,568	153,888	138,320
Total Retail	**1,519,207**	1,533,643	1,546,449	1,526,519	1,445,084	1,335,364
Wholesale	**611,851**	232,138	162,232	150,444	141,902	147,175
Other	**28,810**	26,383	14,466	31,334	13,089	44,823
Total Electric Revenues	**$2,159,868**	$1,792,164	$1,723,147	$1,708,297	$1,600,075	$1,527,362
Natural Gas Deliveries						
(Dekatherms)						
Residential	**20,955**	24,357	25,470	23,512	24,662	25,080
Commercial	**7,898**	10,178	10,146	10,540	10,611	10,640
Industrial	**1,779**	2,409	2,726	2,587	2,180	1,820
Other	**2,568**	2,735	2,230	2,463	2,038	1,805
Transportation of customer-owned natural gas	**20,962**	19,645	20,970	19,433	19,133	18,701
Total Retail	**54,162**	59,324	61,542	58,535	58,624	58,046
Wholesale	**7,527**	3,027	4,056	4,754	–	–
Total Natural Gas Deliveries	**61,689**	62,351	65,598	63,289	58,624	58,046
Natural Gas Revenues						
Residential	**$171,382**	$190,564	$198,338	$181,697	$185,073	$170,734
Commercial	**60,966**	83,091	83,393	75,178	72,360	66,648
Industrial	**8,155**	13,044	14,509	11,310	11,542	9,602
Other	**14,257**	17,839	15,697	14,584	12,997	10,943
Transportation of customer-owned natural gas	**29,589**	21,949	17,476	13,718	12,791	12,091
Total Retail.	**284,349**	326,487	329,413	296,487	294,763	270,018
Wholesale	**17,791**	9,114	10,444	8,771	–	–
Other	**3,741**	2,224	4,528	3,673	4,017	2,769
Total Natural Gas Revenues	**$305,881**	$337,825	$344,385	$308,931	$298,780	$272,787

FINANCIAL STATISTICS

	1998	1997	1996	1995	1994	1993
Financial Statistics						
Return on average common stock equity (Percent)	**11.2**	9.8	9.5	10.4	10.3	9.1
Mortgage bond interest (Times earned)	**4.9**	4.4	4.1	4.0	3.5	3.0
Interest charges and preferred dividends (Times earned)	**2.4**	2.3	2.3	2.2	2.1	1.9
Common stock price at year end	**$56.50**	$35.50	$21.63	$25.88	$19.00	$30.75
Dividend payout ratio (Percent)	**51.3**	54.5	59.1	56.2	84.4	104.8
Price earnings ratio at year end	**18.7**	13.8	9.1	10.4	8.0	14.8
Property, Plant and Equipment (Includes construction work in progress) (Thousands)						
Electric	**$5,315,597**	$5,267,080	$5,208,307	$5,125,336	$5,027,137	$4,887,125
Natural gas	**611,430**	586,144	544,898	472,056	431,202	393,945
Common	**147,265**	162,322	162,758	157,823	171,639	180,532
Total	**$6,074,292**	$6,015,546	$5,915,963	$5,755,215	$5,629,978	$5,461,602
Accumulated Depreciation	**$2,211,608**	$2,093,274	$1,933,599	$1,791,625	$1,642,653	$1,541,456
Number of Shareholders of Record						
Common stock	**33,792**	38,238	45,608	50,576	56,279	58,990
Preferred stock	**803**	1,068	1,211	1,297	1,329	3,632

Selected Financial Data

	1998	1997	1996	1995	1994	1993
(Thousands, except per share amounts)						
Operating Revenues						
Sales and services	$2,499,418	$2,170,102	$2,108,865	$2,040,895	$1,918,431	$1,800,149
Operating Expenses						
Fuel used in electric generation	239,258	233,180	222,102	229,759	231,648	245,283
Electricity purchased	752,978	409,883	360,753	318,440	242,352	161,967
Natural gas purchased	158,656	164,661	180,866	157,476	161,627	141,635
Other operating expenses	366,403	406,830	412,915	367,150	354,553	351,215
Restructuring expenses	–	–	–	–	–	26,000
Maintenance	111,502	110,373	107,697	116,807	106,637	111,757
Depreciation and amortization	191,073	201,768	192,501	188,367	182,598	164,765
Other taxes	204,709	206,446	206,715	210,910	210,729	204,962
Total Operating Expenses	2,024,579	1,733,141	1,683,549	1,588,909	1,490,144	1,407,584
Operating Income	474,839	436,961	425,316	451,986	428,287	392,565
Other Income and Deductions	9,318	11,496	16,403	9,865	2,089	(312)
Interest Charges, Net	125,557	123,199	122,729	129,567	136,092	141,099
Preferred Stock Dividends of Subsidiary	8,583	9,342	9,530	18,721	18,947	20,638
Income Before Federal Income Taxes	331,381	292,924	276,654	293,833	271,159	231,140
Federal Income Taxes	137,176	117,713	107,943	115,864	102,461	85,750
Net Income	194,205	175,211[1]	168,711[2]	177,969	168,698[3]	145,390[4]
Common Stock Dividends	100,487	95,496	99,611	100,104	142,265	152,316
Retained Earnings Increase (Decrease)	$93,718	$79,715	$64,717	$77,865	$26,433	$(6,926)
Average Common Shares Outstanding	64,371	68,153	71,127	71,503	71,254	69,990
Earnings Per Share, basic and diluted	$3.02	$2.57[1]	$2.37[2]	$2.49	$2.37[3]	$2.08[4]
Dividends Paid Per Share	$1.55	$1.40	$1.40	$1.40	$2.00	$2.18
Book Value Per Share of Common Stock at Year End	$27.22	$26.71	$25.41	$24.38	$23.28	$22.89
Capital Spending	$137,350	$129,551	$215,731	$167,446	$282,703	$284,813
Total Assets	$4,883,337	$5,028,681	$5,059,681	$5,114,331	$5,230,685	$5,287,958
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	$1,460,120	$1,475,224	$1,505,814	$1,606,448	$1,776,081	$1,755,629

Reclassifications: Certain amounts included in Selected Financial Data have been reclassified to conform with the 1998 presentation.

[1] Includes the effect of fees related to an unsolicited tender offer that decreased net income by $17 million and earnings per share by 24 cents.

[2] Includes the effect of the writedown of the investment in EnerSoft Corporation that decreased net income by $10 million and earnings per share by 14 cents.

[3] Includes the effect of the 1993 production-cost penalty that decreased net income by $8 million and earnings per share by 12 cents.

[4] Includes the effect of restructuring expenses that decreased net income by $17 million and earnings per share by 25 cents.

REPORT OF INDEPENDENT ACCOUNTANTS

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
1301 Avenue of the Americas
New York NY 10019-6013
Telephone (212) 259 1000
Facsimile (212) 259 1301

January 29, 1999

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 and retained earnings and of cash flows present fairly, in all material respects, the financial position of Energy East Corporation, "the Company," and its subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. 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 generally accepted auditing standards, 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.

PricewaterhouseCoopers LLP

Report of Management

Our 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.

We maintain a system of internal controls designed to provide reasonable assurance to our 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.

We maintain an internal audit department that independently assesses the effectiveness of the internal controls. In addition, our independent accountants, PricewaterhouseCoopers LLP, have considered our internal control structure to the extent they considered necessary in expressing an opinion on the consolidated financial statements. Our management is responsive to the recommendations of our internal audit department and the independent accountants concerning internal controls and corrective measures are taken when considered appropriate. The board of directors oversees our 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. Both the internal auditor and independent accountants have direct access to the audit committee, independent of management.

We assessed our internal control system as of December 31, 1998, 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, we believe that, as of December 31, 1998, our system of internal control over financial reporting and over the safeguarding of assets against loss or unauthorized use met those criteria.

Robt E. Rude

Robert E. Rude
Controller

Wes Von Schack

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

14 Commitments

Capital spending • We have commitments in connection with our capital spending program and estimate that spending, including nuclear fuel, will approximate $140 million for 1999, $127 million for 2000 and $150 million for 2001. Our capital spending program is expected to be financed entirely with internally generated funds. The program is subject to periodic review and revision. Our capital spending will be primarily for the extension of service, necessary improvements to existing facilities and environmental compliance requirements.

Nonutility generator power purchase contracts • We expensed approximately $326 million in 1998, $324 million in 1997 and $320 million in 1996 for NUG power, including termination costs. We estimate that NUG power purchases will total $358 million in 1999 and $376 million in 2000 and in 2001, unless we are able to change the NUG contracts.

15 Quarterly Financial Information (Unaudited)

Quarter ended (Thousands, except per share amounts)	March 31	June 30	Sep. 30	Dec. 31
	1998	**1998**	**1998**	**1998**
Operating Revenues	**$637,630**	**$548,308**	**$698,705**	**$614,775**
Operating Income	**$155,644**	**$87,664**	**$117,447**	**$114,084**
Net Income	**$76,171**	**$29,353**	**$45,050**	**$43,631**
Earnings Per Share, basic and diluted	**$1.15**	**$.46**	**$.71**	**$.69**
Dividends Per Share	**$.35**	**$.40**	**$.40**	**$.40**
Average Common Shares Outstanding	**66,408**	**64,349**	**63,667**	**63,103**
Common Stock Price [1]				
High	**$40.50**	**$44.19**	**$51.38**	**$58.00**
Low	**$33.06**	**$38.94**	**$39.88**	**$46.75**
	1997	**1997**	**1997**	**1997**
Operating Revenues	$599,146	$479,684	$501,779	$589,493
Operating Income	$165,728	$80,766	$81,401	$109,066
Net Income	$79,662	$23,923	$25,929 [2]	$45,697
Earnings Per Share, basic and diluted	$1.15	$.35	$.38 [2]	$.68
Dividends Per Share	$.35	$.35	$.35	$.35
Average Common Shares Outstanding	69,353	68,279	67,503	67,504
Common Stock Price [1]				
High	$24.50	$22.50	$27.19	$35.75
Low	$21.25	$20.63	$20.81	$25.75

[1] Our common stock is listed on the New York Stock Exchange. The number of shareholders of record at December 31, 1998, was 33,792.

[2] Includes the effect of fees related to an unsolicited tender offer that decreased net income by $17 million and earnings per share by 24 cents.

13 Segment Information

Our two primary business segments are electric and natural gas. Our electric business segment consists of electric generation, transmission and distribution operations. Our natural gas business segment consists of natural gas distribution, transportation and storage operations in New York. Other includes our energy services business, natural gas and propane air distribution operations outside of New York, common corporate assets of $201 million in 1998, $139 million in 1997 and $105 million in 1996, and intersegment eliminations. Selected financial information for each of our business segments is presented in the following table.

Year	Electric	Natural Gas	Other	Total
(Thousands)				
1998				
Operating Revenues	$2,159,868	$305,881	$33,669	$2,499,418
Depreciation and Amortization	$172,382	$15,497	$3,194	$191,073
Operating Income	$446,359	$39,743	$(11,263)	$474,839
Interest Charges, Net	$106,195	$17,718	$1,644	$125,557
Federal Income Taxes	$133,111	$7,638	$(3,573)	$137,176
Net Income	$191,460	$11,056	$(8,311)	$194,205
Identifiable Assets	$4,069,627	$575,088	$238,622	$4,883,337
Capital Spending	$96,987	$32,268	$8,095	$137,350
1997				
Operating Revenues	$1,792,164	$337,825	$40,113	$2,170,102
Depreciation and Amortization	$183,304	$15,255	$3,209	$201,768
Operating Income	$380,344	$62,324	$(5,707)	$436,961
Interest Charges, Net	$104,569	$17,113	$1,517	$123,199
Federal Income Taxes	$104,575	$15,212	$(2,074)	$117,713
Net Income	$154,315	$26,482	$(5,586)	$175,211
Identifiable Assets	$4,273,100	$588,773	$166,808	$5,028,681
Capital Spending	$78,667	$45,240	$5,644	$129,551
1996				
Operating Revenues	$1,723,147	$344,385	$41,333	$2,108,865
Depreciation and Amortization	$176,906	$12,495	$3,100	$192,501
Operating Income	$400,262	$57,281	$(32,227)	$425,316
Interest Charges, Net	$108,696	$12,735	$1,298	$122,729
Federal Income Taxes	$102,223	$16,822	$(11,102)	$107,943
Net Income	$167,201	$24,189	$(22,679)	$168,711
Identifiable Assets	$4,376,814	$550,196	$132,671	$5,059,681
Capital Spending	$132,190	$82,625	$916	$215,731

a weighted-average exercise price of $34.28. Of those outstanding at December 31, 1998, 113,155 options/SARs with exercise prices ranging from $21.75 to $34.13 and a weighted-average remaining life of eight years had a weighted-average exercise price of $21.95, and 532,308 options/SARs with exercise prices ranging from $35.88 to $57.44 and a weighted-average remaining life of nine years had a weighted-average exercise price of $36.90. Of those exercisable at December 31, 1998, 113,155 options/SARs with exercise prices ranging from $21.75 to $34.13 had a weighted-average exercise price of $21.95, and 242 options/SARs had an exercise price of $39.25. During 1997 420,479 options/SARs were granted with a weighted-average exercise price of $21.83. 7,933 options and 193,275 SARs with an exercise price of $21.75 were exercised in 1997. 216,792 outstanding options/SARs with a weighted-average exercise price of $21.87 were exercisable at December 31, 1997. 2,479 outstanding options with a weighted-average exercise price of $33.32 were not exercisable at December 31, 1997. We recorded compensation expense for options/SARs of $9.2 million in 1998 and $4.9 million in 1997.

Our Long-Term Executive Incentive Share Plan provides participants cash awards if certain shareholder return criteria are achieved. There were 108,577 performance shares outstanding at December 31, 1998, and compensation expense for 1998 was $5.2 million.

12 Fair Value of Financial Instruments

The carrying amounts and estimated fair values of some of our financial instruments included in our 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	1998 Carrying Amount	1998 Estimated Fair Value	1997 Carrying Amount	1997 Estimated Fair Value
(Thousands)				
Investments held in external trust funds – classified as available-for-sale	$30,097	$30,230	$53,049	$53,708
Preferred stock subject to mandatory redemption requirements	$25,000	$25,188	$25,000	$24,315
First mortgage bonds	$793,157	$861,756	$822,626	$882,616
Pollution control notes	$613,000	$631,421	$613,000	$625,149

The carrying amounts for cash and cash equivalents, commercial paper and interest accrued approximate their estimated fair values because they mature within one year.

Special deposits include restricted funds set aside for preferred stock and long-term debt redemptions. The carrying amount approximates fair value because the special deposits have been invested in securities that mature within one year.

	Pension Benefits			Postretirement Benefits		
	1998	1997	1996	1998	1997	1996
(Thousands)						
Components of net periodic benefit cost						
Service cost	$19,500	$19,317	$18,593	$6,283	$7,010	$6,436
Interest cost	51,556	50,951	46,070	16,606	17,075	15,795
Expected return on plan assets	(84,007)	(73,777)	(62,615)	–	–	–
Amortization of prior service cost	2,016	2,078	661	–	–	–
Recognized net actuarial gain	(26,384)	(18,056)	(11,603)	(4,865)	(3,565)	(3,246)
Amortization of transition (asset) obligation	(7,238)	(7,238)	(7,238)	10,330	10,330	10,330
Deferral for future recovery	–	–	–	(9,600)	(11,766)	(8,950)
Net periodic benefit cost	$(44,557)	$(26,725)	$(16,132)	$18,754	$19,084	$20,365

The net periodic benefit cost for postretirement benefits represents the cost we charged to expense for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred was $10 million as of December 31, 1998, and $14 million as of December 31, 1997. We expect to recover any deferred postretirement costs by the year 2002. The transition obligation for postretirement benefits is being amortized over a period of 20 years.

A one-percent change in the health care cost inflation rate from assumed rates would have the following effects:

	One-Percent Increase	One-Percent Decrease
Effect on total of service and interest cost components	$4 million	$(3 million)
Effect on postretirement benefit obligation	$45 million	$(36 million)

11 Stock-Based Compensation

We apply Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees in accounting for our stock-based compensation plans. Compensation expense would have been the same in 1998, 1997 and 1996 had it been determined consistent with Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation.

We may grant options and stock appreciation rights to senior management and certain other key employees under our stock option plan. Options granted in 1997 vested in 1997, while those granted in 1998 vest over a three-year period, subject to, with certain exceptions, continuous employment. All options expire ten years after the grant date. Of the 3.3 million shares authorized, unoptioned shares totaled 2.3 million at December 31, 1998, and 2.9 million at December 31, 1997.

During 1998 550,308 options/SARs were granted with a weighted-average exercise price of $36.87. 11,438 options with a weighted-average exercise price of $21.75 and 94,678 SARs with a weighted-average exercise price of $21.86 were exercised in 1998. 18,000 options/SARs with an exercise price of $35.88 were forfeited in 1998. The 645,463 options/SARs outstanding at December 31, 1998, had

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites, reflected in our consolidated balance sheets was $79 million at December 31, 1998, and $81 million at December 31, 1997. We recorded a corresponding regulatory asset, net of insurance recoveries, since we expect to recover the net costs in rates.

10 Retirement Benefits

	Pension Benefits		Postretirement Benefits	
	1998	1997	1998	1997
(Thousands)				
Change in projected benefit obligation				
Benefit obligation at January 1	$746,008	$679,778	$258,884	$226,193
Service cost	19,500	19,317	6,283	7,010
Interest cost	51,556	50,951	16,606	17,075
Amendments	–	4,120	–	–
Actuarial loss (gain)	21,831	24,835	(3,889)	16,891
Benefits paid	(35,614)	(32,993)	(8,432)	(8,285)
Projected benefit obligation at December 31	$803,281	$746,008	$269,452	$258,884
Change in plan assets				
Fair value of plan assets at January 1	$1,176,184	$995,795	–	–
Actual return on plan assets	155,956	213,382	–	–
Benefits paid	(35,614)	(32,993)	–	–
Fair value of plan assets at December 31	$1,296,526	$1,176,184	–	–
Funded status	$493,245	$430,176	$(269,452)	$(258,884)
Unrecognized net actuarial gain	(395,780)	(372,046)	(12,847)	(13,824)
Unrecognized prior service cost	26,290	28,307	–	–
Unrecognized net transition (asset) obligation	(37,421)	(44,660)	144,618	154,948
Prepaid (accrued) benefit cost	$86,334	$41,777	$(137,681)	$(117,760)

Our postretirement benefits were unfunded as of December 31, 1998 and 1997.

	Pension Benefits		Postretirement Benefits	
	1998	1997	1998	1997
Weighted-average assumptions as of December 31				
Discount rate	6.5%	7.0%	6.5%	7.0%
Expected return on plan assets	8.5%	8.5%	N/A	N/A
Rate of compensation increase	3.75%	4.25%	N/A	N/A

We assumed a 7% annual rate of increase in the costs of covered health care benefits for 1999 that gradually decreases to 5% by the year 2003.

We have established a Qualified Fund under applicable provisions of the federal tax law to comply with NRC funding regulations. The balance in the fund, including reinvested earnings, was approximately $21 million at December 31, 1998, and $13 million at December 31, 1997. Those amounts are included on the consolidated balance sheets in other property and investments, net. The related liability for decommissioning is included in other liabilities – other. At December 31, 1998, the external trust fund investments were classified as available-for-sale.

Homer City • We have an undivided 50% interest in the output and costs of the Homer City Generating Station, which comprises three generating units. The station is owned with Pennsylvania Electric Company and is operated by its affiliate, GPU Generation, Inc. Our share of the rated capability is 952 megawatts, and our net utility plant investment was approximately $266 million at December 31, 1998, and $262 million at December 31, 1997. The accumulated provision for depreciation was approximately $184 million at December 31, 1998, and $190 million at December 31, 1997. Our share of operating expenses is included in the consolidated statements of income.

We accepted an offer of $900 million in August 1998 for our 50% share of the Homer City Generating Station. (See Note 7. Sale of Coal-fired Generation Assets.)

9 Environmental Liability

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

The U.S. Environmental Protection Agency and the New York State Department of Environmental Conservation, as appropriate, notified us that we are among the potentially responsible parties who may be liable for costs incurred to remediate certain hazardous substances at nine waste sites, not including our sites where gas was manufactured in the past, which are discussed below. With respect to the nine sites, seven sites are included in the New York State Registry of Inactive Hazardous Waste Sites and three of the sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. We recorded an estimated liability of $1 million related to five of the nine 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 us.

We have a program to investigate and perform necessary remediation at our sites where gas was manufactured in the past. In 1994 and 1996, we entered into Orders on Consent with the NYSDEC. These Orders require us to investigate and, where necessary, remediate 34 of our 38 sites. Eight sites are included in the New York State Registry.

Our estimate for all costs related to investigation and remediation of the 38 sites ranges from $79 million to $178 million at December 31, 1998. That estimate is based on both known and potential site conditions and multiple remediation alternatives for each of the sites. The estimate has not been discounted and is based on costs in 1996 dollars that we expect to incur through the year 2017. 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.

8 Jointly-Owned Generating Stations

Nine Mile Point nuclear generating unit No. 2 • We have an 18% interest in the output and costs of NMP2, which is operated by Niagara Mohawk Power Corporation. Ownership of NMP2 is shared with Niagara Mohawk 41%, Long Island Power Authority 18%, Rochester Gas and Electric Corporation 14% and Central Hudson Gas & Electric Corporation 9%.

Our share of the rated capability is 205 megawatts. Our share of net utility plant investment, excluding nuclear fuel, was approximately $573 million at December 31, 1998, and $591 million at December 31, 1997. The accumulated provision for depreciation was approximately $178 million at December 31, 1998, and $162 million at December 31, 1997.

Net proceeds from the sale of our coal-fired generation assets will be used to write down our 18% investment in NMP2. (See Note 7. Sale of Coal-fired Generation Assets.) Our share of operating expenses is included in the consolidated statements of income.

We are actively pursuing the sale of our interest in NMP2. We are working with Niagara Mohawk who is also pursuing the sale of its interest in NMP2.

Nuclear insurance • Niagara Mohawk maintains public liability and property insurance for NMP2. We reimburse Niagara Mohawk for our 18% share of those costs.

The public liability limit for a nuclear incident is approximately $9.1 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. Our maximum liability for our 18% interest in NMP2 would be approximately $15 million per incident. 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. The Price-Anderson Act also requires indemnification for precautionary evacuations whether or not a nuclear incident actually occurs.

Niagara Mohawk has obtained property insurance for NMP2 totaling approximately $2.8 billion through the Nuclear Insurance Pools and Nuclear Electric Insurance Limited. In addition, we have purchased NEIL insurance coverage for the extra expense that would be incurred by purchasing replacement power during prolonged accidental outages. Under NEIL programs, should losses resulting from an incident at a member facility exceed the accumulated reserves of NEIL, each member, including us, would be liable for its share of the deficiency. Our maximum liability per incident under the property damage and replacement power coverage is approximately $2 million.

Nuclear plant decommissioning costs • Based on the results of a 1995 decommissioning study, our 18% share of the cost to decommission NMP2 is $161 million in 1999 dollars ($422 million in 2026 when NMP2's operating license will expire). The estimated liability for decommissioning NMP2 using the Nuclear Regulatory Commission's minimum funding requirement is approximately $101 million in 1999 dollars. Our electric rates in New York State currently include an annual allowance for decommissioning of $4 million, which approximates the minimum funding requirement as set forth in the 1995 decommissioning study. Decommissioning costs are charged to depreciation and amortization expense and are recovered over the expected life of the plant.

Adjustable-rate pollution control notes totaling $132 million were issued to secure the same amount of tax-exempt adjustable-rate pollution control revenue bonds (Adjustable-rate Revenue Bonds) issued by a governmental authority. The Adjustable-rate Revenue Bonds bear interest at rates ranging from 3.58% to 4.18% through dates preceding various annual interest rate adjustment dates. On the annual interest rate adjustment dates the interest rates will be adjusted, or at our option, subject to certain conditions, a fixed rate of interest may become effective. Bond owners may elect, subject to certain conditions, to have their Adjustable-rate Revenue Bonds purchased by the Trustee. We have entered into interest rate swaps to manage the risk of increases in the interest rates on the Adjustable-rate Revenue Bonds, and such swaps are reflected in the above interest rates.

Multi-mode pollution control notes totaling $175 million were issued to secure the same amount of tax-exempt multi-mode pollution control refunding revenue bonds (Multi-mode Revenue Bonds) issued by a governmental authority. The Multi-mode Revenue Bonds have a structure that allows the interest rates to be based on a daily rate, a weekly rate, a commercial paper rate, an auction rate, a term rate or a fixed rate. Bond owners may elect, while the Multi-mode Revenue Bonds bear interest at a daily or weekly rate, to have their bonds purchased by the Registrar and Paying Agent. The maturity dates of the Multi-mode Revenue Bonds are February 1, 2029, June 1, 2029, and October 1, 2029, and can be extended subject to certain conditions. At December 31, 1998, the interest rate for the multi-mode pollution control notes was at the daily rate. The weighted average interest rate for all three series was 3.28%, excluding letter of credit fees, for the year ended December 31, 1998.

NYSEG has irrevocable letters of credit that support certain payments required to be made on the Adjustable-rate Revenue Bonds and Multi-mode Revenue Bonds, and that expire on various dates. If we are unable to extend the letter of credit related to a particular series of Adjustable-rate Revenue Bonds, that series will have to be redeemed unless a fixed rate of interest becomes effective. Multi-mode Revenue Bonds are subject to mandatory purchase when there is any change in the interest rate mode and in certain other circumstances. Payments made under the letters of credit in connection with purchases of Adjustable-rate Revenue Bonds and Multi-mode Revenue Bonds are repaid with the proceeds from the remarketing of those Bonds. To the extent the proceeds are not enough, we are required to reimburse the bank that issued the letter of credit.

7 Sale of Coal-fired Generation Assets

In the spring of 1998 we put our seven coal-fired generating stations and associated assets and liabilities up for auction. The net book value of those coal-fired generation assets was $1.10 billion at December 31, 1998. In August 1998 we accepted two offers totaling $1.85 billion for the coal-fired generation assets. The PSC approved the sales in November 1998 and the FERC approved the sales in January 1999. We expect the sales to close by the end of the first quarter of 1999.

All proceeds, net of taxes and transaction costs, in excess of the net book value of the generation assets, less funded deferred taxes, will be used to write down our 18% investment in Nine Mile Point nuclear generating unit No. 2. This treatment is in accordance with our restructuring plan approved by the Public Service Commission of the State of New York in January 1998. (See Note 8. Jointly-Owned Generating Stations.)

NYSEG has a revolving credit agreement with certain banks that provides for borrowing of up to $200 million through December 31, 2001. The revolving credit agreement does not require compensating balances. We had no outstanding loans under this agreement at December 31, 1998 or 1997. At our option, the interest rate on borrowings is related to the prime rate, the London Interbank Offered Rate or the interest rate applicable to certain certificates of deposit. The agreement provides for payment of a commitment fee, which was .125% at December 31, 1998 and 1997.

6 Long-Term Debt

All of our consolidated long-term debt at December 31, 1998 and 1997, was issued by our subsidiaries.

	Maturity Dates	Interest Rates	Amount 1998	Amount 1997
(Thousands)				
First mortgage bonds (1)	2001 to 2023	6 3/4% to 9 7/8%	$800,000	$830,000
Pollution control notes (2)	2006 to 2034	3.58% to 6.15%	613,000	613,000
Long-term notes	12/31/01		26,200	28,000
Various long-term notes			25,235	12,569
Obligations under capital leases			8,605	12,269
Unamortized premium and discount on debt, net			(6,843)	(7,374)
			1,466,197	1,488,464
Less debt due within one year – included in current liabilities			31,077	38,240
Total			$1,435,120	$1,450,224

At December 31, 1998, long-term debt and capital lease payments that will become due during the next five years are:

1999	2000	2001	2002	2003
(Thousands)				
$31,077	$19,127	$51,867	$151,460	$1,167

(1) NYSEG's first mortgage bond indenture constitutes a direct first mortgage lien on substantially all of its utility plant. The mortgage also provides for a sinking and improvement fund. This provision requires us to make an annual cash deposit with the Trustee equal to 1% of the principal amount of all bonds delivered and authenticated by the Trustee before January 1 of that year (excluding any bonds issued on the basis of the retirement of bonds). Pursuant to the terms of the mortgage, we satisfied the requirement in 1998 by crediting "bondable value of property additions" against the amount of cash to be deposited. We redeemed, in March 1998, $30 million of 6 1/2% Series first mortgage bonds, due September 1, 1998.

(2) Fixed-rate pollution control notes totaling $306 million were issued to secure the same amount of tax-exempt pollution control revenue bonds issued by a governmental authority. The interest rates range from 5.70% to 6.15%.

4 Preferred Stock of Subsidiary

At December 31, 1998 and 1997, NYSEG's serial cumulative preferred stock was:

Series	Par Value Per Share	Redemption Price Per Share	Shares Authorized and Outstanding (1)	Amount 1998	Amount 1997
(Thousands)					
Redeemable solely at the option of the company:					
3.75%	$100	$104.00	150,000	$15,000	$15,000
4 1/2% (1949)	100	103.75	40,000	4,000	4,000
4.15%	100	101.00	14,000	1,400	1,400
4.40%	100	102.00	55,200	5,520	5,520
4.15% (1954)	100	102.00	35,200	3,520	3,520
6.48% (2)	100		–	–	30,000
7.40% (3)	25	25.00	1,000,000	25,000	25,000
Adjustable Rate (3)	25	25.00	2,000,000	50,000	50,000
				104,440	134,440
Less preferred stock redemptions due within one year – included in current liabilities				75,000	–
Total				$29,440	$134,440
Subject to mandatory redemption requirements:					
6.30% (4)	100	102.52	250,000	$25,000	$25,000

(1) At December 31, 1998, there were 1,910,600 shares of $100 par value preferred stock, 7,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued. After giving effect to the redemptions referred to in (3) below, there will be 10,800,000 shares of $25 par value preferred stock authorized but unissued.

(2) Redeemed July 1, 1998.

(3) To be redeemed February 1, 1999.

(4) On January 1 of each year from 2004 through 2008, we must redeem 12,500 shares at par, and on January 1, 2009, we must redeem the balance of the shares at par. This Series is redeemable at our option at $102.52 per share before January 1, 2000. The $102.52 price will be reduced annually by 63 cents for the years ending 2000 through 2002; thereafter, the redemption price is $100.00. We are restricted in our ability to redeem this Series before January 1, 2004.

5 Bank Loans and Other Borrowings

We use short-term, unsecured notes, usually commercial paper, to finance certain refundings and for other corporate purposes. The weighted average interest rate on commercial paper balances, all of which belonged to NYSEG, was 6.2% at December 31, 1998, and 6.3% at December 31, 1997.

3 Income Taxes

Year ended December 31	1998	1997	1996
(Thousands)			
Current	$98,427	$111,829	$79,015
Deferred, net			
Accelerated depreciation	20,684	29,070	52,572
Miscellaneous	22,718	(18,130)	(17,307)
ITC	(4,653)	(5,056)	(6,337)
Total	**$137,176**	$117,713	$107,943

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

Year ended December 31	1998	1997	1996
(Thousands)			
Tax expense at statutory rate	$118,987	$105,792	$100,165
Depreciation not normalized	16,776	16,854	20,542
ITC amortization	(6,354)	(6,359)	(6,337)
Other, net	7,767	1,426	(6,427)
Total	**$137,176**	$117,713	$107,943

Our deferred tax assets and liabilities consisted of the following:

December 31	1998	1997
(Thousands)		
Current Deferred Tax Assets	–	$2,148
Current Deferred Tax Liabilities	$10,029	–
Noncurrent Deferred Taxes		
Depreciation	$775,034	$775,943
Unfunded future federal income taxes	60,896	99,126
Accumulated deferred ITC	109,987	114,640
Future income tax benefit – ITC	(37,584)	(40,087)
Other	14,192	(16,399)
Total Noncurrent Deferred Tax Liabilities	922,525	933,223
Valuation Allowance	2,001	1,611
Less amounts classified as regulatory liabilities		
Deferred income taxes	98,038	81,986
Deferred income taxes – unfunded future federal income taxes	60,896	99,126
Noncurrent Deferred Income Taxes	$765,592	$753,722

Regulatory assets and liabilities • Pursuant to Statement 71, we capitalize, as regulatory assets, incurred costs that are probable of recovery in future electric and natural gas rates. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. In accordance with our current rate agreements in New York State, we no longer defer most costs that were previously subject to deferral accounting.

Unfunded future federal income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized debt expense is amortized over the lives of the related debt issues. Demand-side management program costs, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with our current New York State rate agreements. We earn a return on all regulatory assets for which funds have been spent.

Consolidated statements of cash flows • We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents. Those investments are included in cash and cash equivalents on the consolidated balance sheets.

Total income taxes paid were $92 million in 1998, $111 million in 1997 and $98 million in 1996.

Interest paid, net of amounts capitalized, was $104 million in 1998, $107 million in 1997 and $112 million in 1996.

Risk management • We use natural gas futures and options contracts to manage our exposure to fluctuations in natural gas commodity prices. Such contracts allow us to fix margins on sales of natural gas generally expected to occur over the next 18 months. The cost or benefit of natural gas futures and options contracts is included in the commodity cost when the related sales commitments are fulfilled.

We use electricity contracts to manage our exposure to fluctuations in the cost of electricity. Such contracts allow us to fix margins on the majority of our retail and wholesale sales of electricity. The cost or benefit of electricity contracts is included in the cost of electricity purchased when the electricity is sold.

We use interest rate swap agreements to manage the risk of increases in variable interest rates. We record amounts paid and received under the agreements as adjustments to the interest expense of the specific debt issues.

Gains and losses resulting from the use of risk management techniques in 1998 and 1997 were not material to our financial position or results of operations. We do not hold or issue financial instruments for trading or speculative purposes.

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.

Reclassifications • Certain amounts have been reclassified on the consolidated financial statements to conform with the 1998 presentation.

1 Holding Company Formation

Energy East Corporation is an energy delivery, products and services company with operations in New York, Massachusetts, Maine, New Hampshire, Vermont and New Jersey. We deliver electricity and natural gas to retail customers and provide electricity, natural gas and energy management and other services to retail and wholesale customers in the Northeast.

On May 1, 1998, Energy East Corporation became the parent of New York State Electric & Gas Corporation pursuant to an Agreement and Plan of Share Exchange. Each share of NYSEG's outstanding common stock was exchanged for a share of Energy East's common stock.

2 Significant Accounting Policies

Principles of consolidation • These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

Depreciation and amortization • We determine depreciation expense using straight-line rates, based on the average service lives of groups of depreciable property in service. Our depreciation accruals were equivalent to 3.4% of average depreciable property for 1998 and 3.5% for 1997 and 1996. Amortization expense includes the amortization of certain regulatory assets authorized by the PSC.

Accounts receivable • We have an agreement that expires in November 2001 to sell, with limited recourse, undivided percentage interests in certain of our accounts receivable from customers. The agreement allows us to receive up to $152 million from the sale of such interests. At December 31, 1998 and 1997, 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 are included in other income and deductions on the consolidated statements of income and amounted to approximately $9 million in 1998, 1997 and 1996. Accounts receivable on the consolidated balance sheets are also shown net of an allowance for doubtful accounts of $9 million at December 31, 1998, and $7 million at December 31, 1997. Bad debt expense was $18 million in 1998, $17 million in 1997 and $19 million in 1996.

Income taxes • We file 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 are amortized over the estimated lives of the related assets.

Utility plant • We charge repairs and minor replacements to operating expense accounts. We capitalize 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.

Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)

	Common Stock Outstanding[1] Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Treasury Stock	Total
Balance, January 1, 1996	71,503	$476,686	$842,442	$424,412	–	$1,743,540
Net income				168,711		168,711
Common stock dividends declared ($1.40 per share)				(99,611)		(99,611)
Common stock repurchased	(1,833)	(12,217)	(27,981)			(40,198)
Premium paid on redemption of subsidiary's preferred stock, net				(4,383)		(4,383)
Amortization of capital stock issue expense			1,923			1,923
Balance, December 31, 1996	69,670	464,469	816,384	489,129	–	1,769,982
Net income				175,211		175,211
Common stock dividends declared ($1.40 per share)				(95,496)		(95,496)
Common stock repurchased	(333)	(2,219)	(5,026)			(7,245)
Treasury stock transactions, net	(1,829)		56		$(39,447)	(39,391)
Amortization of capital stock issue expense			234			234
Balance, December 31, 1997	67,508	462,250	811,648	568,844	(39,447)	1,803,295
Net income				194,205		194,205
Common stock dividends declared ($1.55 per share)				(100,487)		(100,487)
Common stock repurchased	(4,425)	(20,015)	(157,228)			(177,243)
Treasury stock transactions, net	(136)	(12,192)	(27,235)		31,836	(7,591)
Change in par value of common stock		(429,412)	429,412			–
Amortization of capital stock issue expense			1,307			1,307
Balance, December 31, 1998	62,947	$631	$1,057,904	$662,562	$(7,611)	$1,713,486

[1] Par value of $.01 at December 31, 1998, and $6.66 2/3 at December 31, 1997 and 1996 and January 1, 1996.

The notes on pages 17 through 29 are an integral part of the financial statements.

Consolidated Statements of Cash Flows

Year Ended December 31	1998	1997	1996
(Thousands)			
Operating Activities			
Net income	$194,205	$175,211	$168,711
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	191,073	201,768	192,501
Federal income taxes and investment tax credits deferred, net	38,749	5,884	28,928
Changes in current operating assets and liabilities			
Accounts receivable	40,296	35	6,791
Prepayments	(42,630)	(21,283)	(15,798)
Accounts payable and accrued liabilities	(8,399)	3,858	3,486
Taxes accrued	(5,559)	6,146	(22,231)
Other, net	60,052	75,115	84,932
Net Cash Provided by Operating Activities	467,787	446,734	447,320
Investing Activities			
Utility plant additions	(130,417)	(123,768)	(214,373)
Proceeds from governmental and other sources	1,368	1,443	2,977
Other property and investment	19,070	(57,803)	(916)
Net Cash Used in Investing Activities	(109,979)	(180,128)	(212,312)
Financing Activities			
Repurchase of common stock	(177,243)	(7,245)	(40,198)
Treasury stock acquired, net	(7,611)	(39,447)	–
Repayments of first mortgage bonds and preferred stock, including net premiums	(60,600)	(73,000)	(171,478)
Changes in funds set aside for first mortgage bond repayments	–	25,000	(25,000)
Long-term notes, net	7,733	(5,203)	(2,581)
Commercial paper, net	20,300	(71,300)	100,680
Dividends on common stock	(100,487)	(95,496)	(99,611)
Net Cash Used in Financing Activities	(317,908)	(266,691)	(238,188)
Net Increase (Decrease) in Cash and Cash Equivalents	39,900	(85)	(3,180)
Cash and Cash Equivalents, Beginning of Year	8,168	8,253	11,433
Cash and Cash Equivalents, End of Year	$48,068	$8,168	$8,253

The notes on pages 17 through 29 are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31	1998	1997	1996
(Thousands, except per share amounts)			
Operating Revenues			
Sales and services	$2,499,418	$2,170,102	$2,108,865
Operating Expenses			
Fuel used in electric generation	239,258	233,180	222,102
Electricity purchased	752,978	409,883	360,753
Natural gas purchased	158,656	164,661	180,866
Other operating expenses	366,403	406,830	412,915
Maintenance	111,502	110,373	107,697
Depreciation and amortization	191,073	201,768	192,501
Other taxes	204,709	206,446	206,715
Total Operating Expenses	2,024,579	1,733,141	1,683,549
Operating Income	474,839	436,961	425,316
Other Income and Deductions	9,318	11,496	16,403
Interest Charges, Net	125,557	123,199	122,729
Preferred Stock Dividends of Subsidiary	8,583	9,342	9,530
Income Before Federal Income Taxes	331,381	292,924	276,654
Federal Income Taxes	137,176	117,713	107,943
Net Income	$194,205	$175,211	$168,711
Earnings Per Share, basic and diluted	$3.02	$2.57	$2.37
Average Common Shares Outstanding	64,371	68,153	71,127

The notes on pages 17 through 29 are an integral part of the financial statements.

Consolidated Balance Sheets

December 31	1998	1997
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$31,077	$38,240
Current portion of preferred stock of subsidiary	75,000	–
Commercial paper	78,300	58,000
Accounts payable and accrued liabilities	116,582	124,981
Interest accrued	19,556	20,500
Taxes accrued	587	6,146
Accumulated deferred federal income tax, net	10,029	–
Other	82,143	79,631
Total Current Liabilities	413,274	327,498
Regulatory and Other Liabilities		
Regulatory liabilities		
Deferred income taxes	98,038	81,986
Deferred income taxes – unfunded future federal income taxes	60,896	99,126
Other	42,182	79,709
Total regulatory liabilities	201,116	260,821
Other liabilities		
Deferred income taxes	765,592	753,722
Other postretirement benefits	137,681	117,760
Environmental remediation costs	80,600	82,900
Other	82,028	73,021
Total other liabilities	1,065,901	1,027,403
Long-term debt	1,435,120	1,450,224
Total Liabilities	3,115,411	3,065,946
Commitments	–	–
Preferred Stock of Subsidiary		
Preferred stock redeemable solely at the option of subsidiary	29,440	134,440
Preferred stock subject to mandatory redemption requirements	25,000	25,000
Common Stock Equity		
Common stock ($.01 par value, 200,000 shares authorized and 62,947 shares outstanding as of December 31, 1998, and $6.66 2/3 par value, 90,000 shares authorized and 67,508 shares outstanding as of December 31, 1997)	631	462,250
Capital in excess of par value	1,057,904	811,648
Retained earnings	662,562	568,844
Treasury stock, at cost (136 shares at December 31, 1998, and 1,829 shares at December 31, 1997)	(7,611)	(39,447)
Total Common Stock Equity	1,713,486	1,803,295
Total Liabilities and Stockholders' Equity	$4,883,337	$5,028,681

The notes on pages 17 through 29 are an integral part of the financial statements.

CONSOLIDATED BALANCE SHEETS

December 31	1998	1997
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$48,068	$8,168
Special deposits	4,729	3,170
Accounts receivable, net	148,712	189,008
Fuel, at average cost	44,643	43,706
Materials and supplies, at average cost	38,040	41,561
Prepayments	111,082	68,452
Accumulated deferred federal income tax benefits, net	–	2,148
Total Current Assets	395,274	356,213
Utility Plant, at Original Cost		
Electric	5,299,604	5,234,725
Natural gas	602,904	576,683
Common	144,043	152,034
	6,046,551	5,963,442
Less accumulated depreciation	2,211,608	2,093,274
Net Utility Plant in Service	3,834,943	3,870,168
Construction work in progress	27,741	52,104
Total Utility Plant	3,862,684	3,922,272
Other Property and Investments, Net	129,088	143,449
Regulatory and Other Assets		
Regulatory assets		
Unfunded future federal income taxes	136,404	243,129
Unamortized debt expense	71,530	76,418
Demand-side management program costs	64,466	64,466
Environmental remediation costs	60,600	82,900
Other	125,604	113,637
Total regulatory assets	458,604	580,550
Other assets	37,687	26,197
Total Regulatory and Other Assets	496,291	606,747
Total Assets	$4,883,337	$5,028,681

The notes on pages 17 through 29 are an integral part of the financial statements.

OPERATING RESULTS FOR THE NATURAL GAS BUSINESS SEGMENT

(Thousands)	1998	1997	1996	1998 over 1997 Change	1997 over 1996 Change
Retail Deliveries – Dekatherms	**54,162**	59,324	61,542	(9%)	(4%)
Wholesale Deliveries – Dekatherms	**7,527**	3,027	4,056	149%	(25%)
Operating Revenues	**$305,881**	$337,825	$344,385	(9%)	(2%)
Operating Expenses	**$266,138**	$275,501	$287,104	(3%)	(4%)
Operating Income	**$39,743**	$62,324	$57,281	(36%)	9%

Our natural gas deliveries decreased in 1998 primarily due to warmer weather, and decreased in 1997 due to one low-margin customer that closed its cogeneration plant. Excluding the loss of that customer, 1997 natural gas deliveries increased 2% over 1996.

Operating Revenues: Our 1998 natural gas operating revenues decreased by $32 million. Revenues were reduced $48 million by lower retail deliveries, primarily due to warmer weather. That decrease was partially offset by a $13 million increase in wholesale deliveries.

The $7 million decrease in 1997 natural gas operating revenues was primarily due to lower retail deliveries that reduced revenues $12 million and a $3 million decrease in other revenues. Those decreases were partially offset by a more favorable sales mix that added $9 million to revenues.

Operating Expenses: Our 1998 natural gas operating expenses decreased $9 million due to a $6 million decrease in the cost of natural gas purchased and a $3 million decrease in other operating costs due to the effect of a 1997 nonrecurring charge.

Our 1997 natural gas operating expenses decreased $12 million due to a decrease in the cost of natural gas purchased of $16 million, partially offset by an increase in operating costs of $3 million that was due to a nonrecurring charge.

OPERATING RESULTS FOR THE ELECTRIC BUSINESS SEGMENT

(Thousands)	1998	1997	1996	1998 over 1997 Change	1997 over 1996 Change
Retail Deliveries – Megawatt-hours	**13,277**	13,238	13,216	–	–
Wholesale Deliveries – Megawatt-hours	**22,711**	10,406	7,914	118%	31%
Operating Revenues	**$2,159,868**	$1,792,164	$1,723,147	21%	4%
Operating Expenses	**$1,713,509**	$1,411,820	$1,322,885	21%	7%
Operating Income	**$446,359**	$380,344	$400,262	17%	(5%)

Operating Revenues: Our 1998 electric operating revenues increased $368 million due to an increase in wholesale deliveries and higher wholesale prices totaling $380 million, partially offset by an $8 million decrease due to lower retail prices.

Our 1997 electric operating revenues increased $69 million over 1996 due to a $70 million increase in wholesale deliveries.

Operating Expenses: Our 1998 electric operating expenses increased $302 million due to a $343 million increase in electricity purchased for wholesale deliveries, partially offset by a $34 million decrease in other operating and maintenance costs primarily due to cost control efforts and the effect of a 1997 nonrecurring charge.

Our 1997 electric operating expenses increased $89 million primarily due to a $49 million increase in electricity purchased, due to purchases for wholesale deliveries and the price of NUG power. Expenses also increased as a result of a $19 million increase in operating costs, primarily due to the effect of a 1997 nonrecurring charge, and an $11 million increase in fuel costs, due to increased electric generation.

energy services; our ability to compete in the rapidly changing and increasingly competitive electric and natural gas utility markets; our ability to control nonutility generator and other costs; changes in fuel supply or cost and the success of our strategies to satisfy our electric energy requirements after our coal-fired generating stations are sold; our ability to expand our products and services, including our energy distribution network in the Northeast; the ability to obtain adequate and timely rate relief; nuclear or environmental incidents; legal or administrative proceedings; changes in the cost or availability of capital; growth in the areas in which we are doing business; weather variations affecting customer energy usage; and other considerations that may be disclosed from time to time in our publicly disseminated documents and filings. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

Results of Operations

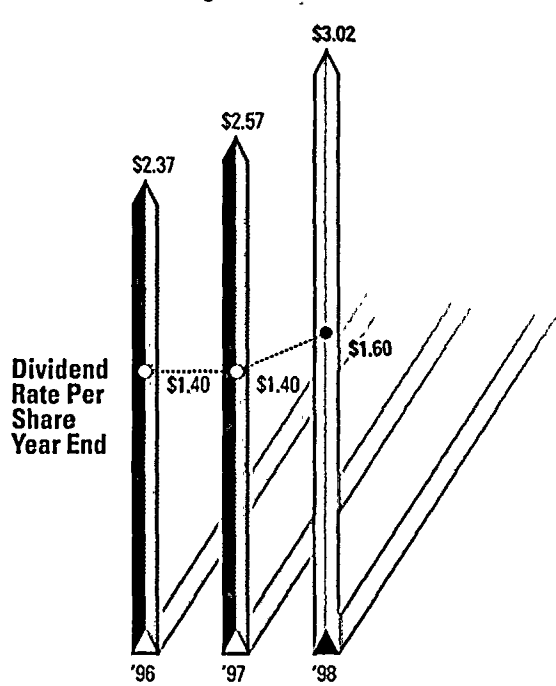
(Thousands, except per share amounts)	1998	1997	1996	1998 over 1997 Change	1997 over 1996 Change
Total Operating Revenues	**$2,499,418**	$2,170,102	$2,108,865	15%	3%
Operating Income	**$474,839**	$436,961	$425,316	9%	3%
Net Income	**$194,205**	$175,211	$168,711	11%	4%
Average Shares Outstanding	**64,371**	68,153	71,127	(6%)	(4%)
Earnings Per Share, basic and diluted	**$3.02**	$2.57	$2.37	18%	8%
Earnings Per Share Excluding Certain Charges	**$3.02**	$2.81	$2.51	7%	12%
Dividends Paid Per Share	**$1.55**	$1.40	$1.40	11%	–

EARNINGS PER SHARE

Our earnings per share increased in 1998 primarily due to higher electric wholesale prices and higher electric wholesale deliveries, cost control efforts and a reduction in the number of common shares outstanding. Those increases were partially offset by lower natural gas retail deliveries, primarily because of unusually warm winter weather, and lower electric retail prices. The 1997 earnings per share include the effect of a nonrecurring charge of 24 cents per share.

Excluding the net effects of nonrecurring items, our earnings per share for 1997 increased compared to 1996 primarily due to higher electric wholesale deliveries, lower costs of natural gas purchased and a reduction in the number of common shares outstanding. Those increases were partially offset by a decrease in earnings per share due to the price of NUG power.

Earnings Per Share



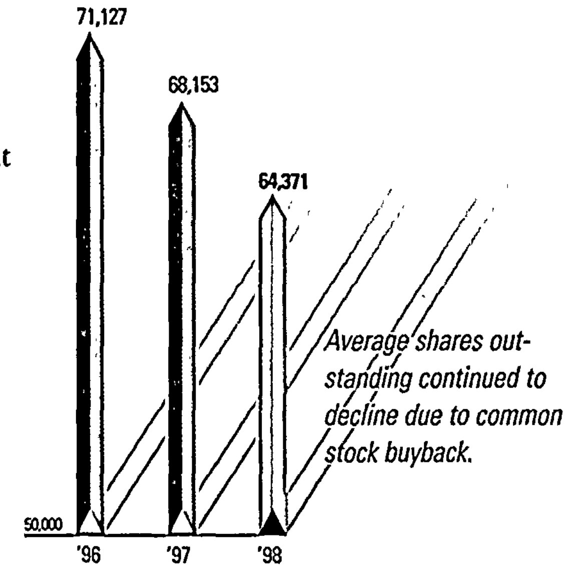
We repurchased 4.6 million shares of our common stock during 1998.

We raised the common stock dividend in January 1999 to a new annual rate of $1.68.

In January 1999 we declared a two-for-one stock split on common stock outstanding. Shareholders of record at the close of business on March 12, 1999, will be entitled to the shares on April 1, 1999.

We use short-term, unsecured notes, usually commercial paper, to finance certain refundings and for other corporate purposes. We had $78 million of commercial paper outstanding at December 31, 1998, and $58 million outstanding at December 31, 1997, all of which was issued by NYSEG. The weighted average interest rate for commercial paper was 6.2% at December 31, 1998, and 6.3% at December 31, 1997.

Average Shares Outstanding
(Thousands)



NYSEG also has a revolving credit agreement with certain banks that provides for borrowing of up to $200 million until December 31, 2001. We had no amounts outstanding under this agreement during 1998 or 1997.

We use interest rate swap agreements to manage the risk of increases in variable interest rates. We record amounts paid and received under the agreements as adjustments to the interest expense of the specific debt issues.

FORWARD-LOOKING STATEMENTS

This Annual Report to Shareholders 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 risk that more Year 2000 problems may be found as we continue the review of our systems; the risk that our progress in addressing Year 2000 problems may not proceed as we expect; the fact that despite all of our efforts, there can be no assurances that all of our Year 2000 issues can or will be remedied; the fact that there can be no assurances that all Year 2000 issues that could affect us can or will be totally eliminated by our suppliers, customers, neighboring or interconnected utilities and other entities; and the fact that our assessment of the effects of Year 2000 issues are based, in part, upon information received from our suppliers, customers, neighboring or interconnected utilities and other entities, our reasonable reliance upon this information and the risk that inaccurate or incomplete information may have been supplied to us.

Some additional factors that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others, the deregulation and unbundling of

Additionally, we are dependent on others for our supply of natural gas. In the event one of our suppliers is not able to meet our needs, we plan to purchase the needed amount of natural gas from one of our many other suppliers on the same transmission line. Since we expect to sell our coal-fired generation stations by the end of the first quarter of 1999, we will be buying instead of producing the majority of the electricity our customers need by the beginning of the year 2000. If the electricity available in our region is not adequate for all of the customers on our system, we plan to operate at lower levels of power as outlined in our established emergency procedures. Should our mainframe hardware be disabled, we have a backup mainframe system that is capable of operating all of our business systems. We expect to have all of our contingency plans ready and tested by mid-1999.

The PSC issued an Order on October 30, 1998, adopting a July 1, 1999, deadline for New York utilities to complete their Year 2000 readiness programs for "mission critical" systems and for contingency plans. Mission critical systems include those systems that control the acquisition and the delivery of electricity and natural gas to customers, emergency management systems and certain electric generation plants. We believe that our Year 2000 readiness program for mission critical systems and for contingency plans will be completed by the PSC's July 1, 1999, deadline. The PSC Order requires the filing of status reports with the PSC regarding certain Year 2000 issues. We filed our first status report in December 1998 and plan to file our next status report prior to the July 1, 1999, deadline.

INVESTING AND FINANCING ACTIVITIES

Investing Activities • Capital spending, including nuclear fuel, totaled $137 million in 1998, $130 million in 1997 and $216 million in 1996. Capital spending in those three years was financed entirely with internally generated funds and was primarily for the extension of service, necessary improvements to existing facilities and compliance with environmental requirements.

Capital spending, including nuclear fuel, is projected to be $140 million in 1999, $127 million in 2000 and $150 million in 2001, and is expected to be paid for entirely with internally generated funds.

Financing Activities • Our current financial strength provides the flexibility required to compete in a competitive energy market and continue expanding our products and services, including our distribution system, in the Northeast.

Our financing-related activities during 1998 consisted of:

- redemption of $30 million of 6 1/2% Series first mortgage bonds;
- redemption, at a premium, of $30 million of 6.48% preferred stock; and
- use of interest rate swaps to fix the interest rates on our three one-year, adjustable-rate, tax-exempt issues totaling $132 million.

Our mainframe systems consist of the hardware and software components of NYSEG's information technology systems. We believe we have identified, taken appropriate corrective action and tested all of our mainframe systems. We believe those systems are now able to process year 2000 and beyond transactions.

Our special-purpose systems consist of our non-information technology systems and the information technology systems of our subsidiaries other than NYSEG. We have identified approximately 6,000 items in our special-purpose systems that may be affected by the Year 2000 problem. Items identified include software, hardware and embedded chips in systems such as those that control the acquisition and the delivery of electricity and natural gas to customers and those in our communication systems. We believe we have fixed, eliminated, replaced or found no problem with over 90% of the special-purpose items we have identified, including those in our electric and natural gas delivery systems. We are determining and taking appropriate corrective action for the remaining identified items. Additional items, however, continue to be identified as we proceed with the review of our special-purpose systems. We expect to have reviewed, identified and determined and taken the appropriate corrective action on all of our special-purpose systems by the end of the second quarter of 1999.

Even though we believe we will have taken corrective action with respect to our own Year 2000 issues, the Year 2000 issue could adversely affect us if there are items in our mainframe or special-purpose systems that may be affected by the Year 2000 problem and that we have not identified in our review of those systems. The Year 2000 issue could also adversely affect us if third parties such as suppliers, customers, neighboring or interconnected utilities and other entities fail to correct any of their Year 2000 problems. We have contacted key third parties to determine the status of their Year 2000 readiness programs. Many have responded satisfactorily, some have not responded satisfactorily and some have not responded at all. We are developing contingency plans, some of which are discussed below, for reasonably likely worst case scenarios based upon an assumption that we and those third parties will not be Year 2000 compliant.

Our Year 2000 program is progressing on schedule and we believe we are taking all necessary steps to address this issue successfully. Through 1998 we have spent approximately $11.4 million and expect to spend an additional $0.8 million on Year 2000 readiness. We believe this amount is adequate to address our Year 2000 issues. These amounts are being expensed as incurred and are being financed entirely with internally generated funds. Addressing the Year 2000 issue has not caused us to delay any significant information system projects.

As part of our normal business practice we have plans in place for use during emergencies, some of which could arise from Year 2000 problems. We are completing contingency plans to specifically address reasonably likely worst case scenarios that could arise as a result of the Year 2000 problem.

The contingency plans will address, among other scenarios, the interruption or failure of normal business activities or operations such as a partial electrical and/or natural gas system shutdown. If the interruption or failure is due to embedded chips in equipment such as automatic control devices, our contingency plan is to implement the normal system restoration procedures that we utilize during emergencies. If the interruption or failure is due to telecommunications not being available, we plan to use alternative communication devices such as satellite phones. Another scenario is the failure of our customer information system. Should that occur, we plan to rely on customer information previously stored and make the appropriate adjustment to each customer's next bill after the system is restored.

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 we believe we will continue to meet the criteria of Statement 71 for our regulated electric and natural gas operations in New York State, we cannot predict what effect a competitive market or future PSC actions will have on our ability to continue to do so. If we can no longer meet the criteria of Statement 71 for all or a separable part of our regulated operations, we may have to record as expense or revenue certain regulatory assets and liabilities. We may also have to record as a loss an estimated $1.5 billion, on a present value basis at December 31, 1998, of above-market costs on our power purchase contracts with NUGs. These items are currently recovered in rates.

With approval of our restructuring plan in January 1998, we discontinued application of Statement 71 to our coal-fired generation operations and applied Statement of Financial Accounting Standards No. 101, Regulated Enterprises—Accounting for the Discontinuance of Application of FASB Statement No. 71. Application of Statement 101 did not affect our financial position or results of operations. (See Electric Business, Sale of our Coal-fired Generation Assets.)

Statement 133: The FASB issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, in June 1998. Statement 133 establishes standards for the accounting and reporting for derivative instruments and for hedging activities. Statement 133 requires that all derivatives be recognized as either assets or liabilities on a company's balance sheet at their fair market value. We plan to adopt Statement 133 as of the beginning of the first quarter of 2000. Based on our current risk management strategies, this adoption is not expected to have a material effect on our financial position or results of operations.

EITF 98-10: In November 1998 the FASB's Emerging Issues Task Force reached a consensus on Issue Number 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities. EITF 98-10 requires that energy trading activity be measured at fair value on the balance sheet with gains and losses recognized in current earnings. Based on our current energy procurement strategies, the implementation of EITF 98-10 in 1999 is not expected to have a material effect on our financial position or results of operations.

Year 2000 Readiness Disclosure • Many of our computer systems, which include mainframe systems and special-purpose systems, refer to years in terms of their final two digits only. Such systems may interpret the year 2000 as the year 1900. If not corrected, those systems could cause us to, among other things, experience energy delivery problems, report inaccurate data or issue inaccurate bills.

We are working diligently to address this problem by reviewing all of our mainframe and special-purpose systems; identifying potentially affected software, hardware, and date-sensitive components, often referred to as embedded chips, of various equipment; determining and taking appropriate corrective action; and, when appropriate, testing our systems.

The PSC's Order requires local distribution companies, effective April 1, 1999, to cease assigning capacity costs to customers who switch from distribution service to transportation service. The local distribution companies will be provided a reasonable opportunity to recover any capacity costs that may be stranded. We expect to recover all costs associated with our customers switching to transportation service.

Natural Gas Commodity Prices: We use risk management techniques such as natural gas futures and options contracts to manage our exposure to fluctuations in natural gas commodity prices. Such contracts allow us to fix margins on sales of natural gas generally expected to occur over the next 18 months. The cost or benefit of natural gas futures and options contracts is included in the commodity cost when the related sales commitments are fulfilled. Gains and losses resulting from the use of those contracts for 1998, 1997 and 1996 were not material to our financial position or results of operations.

OTHER OPERATIONS

XENERGY Enterprises, Inc. • We invest in providers of energy, telecommunications and financial services.

XENERGY: We provide energy services, information systems and energy consulting to utilities, governmental agencies and end-use energy consumers, primarily commercial and industrial.

Energy East Solutions: We market electricity and natural gas to end-use customers and wholesale markets in the Northeast. In October 1998 Energy East Solutions formed a joint venture with South Jersey Energy Company to market retail electricity and energy management services in the mid-Atlantic region.

Energy East Enterprises, Inc. • We own natural gas and propane air distribution companies outside of New York State.

CMP Natural Gas LLC: We signed an agreement with Central Maine Power Company in November 1997 to form a jointly-owned company to distribute natural gas in Maine and New Hampshire to customers who are not currently served. CMP Natural Gas has received approval from the Maine Public Utilities Commission to provide service to 60 towns in Maine. CMP Natural Gas' plans have been developed to coincide with the construction schedules of two natural gas pipelines from Canada. One pipeline began construction in mid-1998 and the other is expected to begin in early 1999. CMP Natural Gas expects initial service to customers in mid-1999.

New Hampshire Gas Corporation: We established a presence in New Hampshire with our purchase of a franchise and propane air distribution system in Keene, New Hampshire. Our short-term plans call for the continuation of the existing propane air distribution system. Long-term plans call for bringing natural gas to the Keene area.

Southern Vermont Natural Gas: We are working with Iroquois Gas Transmission System and Vermont Energy Park Holdings to develop a combined natural gas supply and electric generation project. The proposal includes an extension of an Iroquois pipeline from New York to Vermont, two combined-cycle electric generating plants, and natural gas distribution to industrial, commercial and residential customers. Our role in the project will be to construct a natural gas pipeline from the new Iroquois pipeline to the electric generating plants and to build distribution systems to provide natural gas service to industrial, commercial and residential customers along the pipeline.

The restructuring plan will save customers an estimated $725 million over five years. Specifically the plan:

- eliminates a 7% increase in electricity prices previously approved by the PSC;
- reduces prices 5% each year in the five years of the plan for eligible industrial, commercial and public authority customers who are heavy users of electricity;
- caps the overall average prices for all other customers for four years and reduces their prices 5% at the beginning of the fifth year;
- allows all of our retail customers to choose their electricity supplier by August 1, 1999; and
- includes a 12% return on equity cap and a 9% floor, exclusive of common stock repurchases, during each of the five years of the price cap.

NATURAL GAS BUSINESS

Our natural gas business delivers, transports and stores natural gas in New York State.

New Franchises: We are growing our natural gas business in New York by expanding natural gas service in existing franchise areas and by developing new franchises. We began developing eight new franchises during 1998.

Natural Gas Rate Agreement: We filed a natural gas rate agreement with the PSC in May 1998. This agreement cuts prices for most customers by reducing natural gas revenues by $25.6 million, or 2.1%, over the four-year period ending September 30, 2002. The PSC approved the agreement in September 1998 after making certain modifications. After seeking clarification of the modifications from the PSC Staff, we accepted the PSC Order with the clarifications and one modification that maintains present rates for certain areas. The PSC accepted our clarifications and modification and issued an order in December 1998.

Seneca Lake Natural Gas Storage Facility: Our Seneca Lake natural gas storage facility includes a natural gas storage cavern, a compressor station and a natural gas transmission pipeline. The facility is located on Seneca Lake north of Watkins Glen and began operations in 1996. We built this facility to ensure an adequate natural gas supply to customers, to support economic growth in southern and central New York and to increase supply flexibility.

We expanded the facility in 1997 to increase the cavern's working capacity from 800 million to 1.45 billion cubic feet of natural gas and the compressor station's deliverability from 80,000 to 145,000 dekatherms per day. This expansion allows for the sale of storage capacity.

Role of Local Distribution Companies: The PSC, on November 3, 1998, issued a "Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment." The policy statement includes the PSC's vision for furthering competition in the natural gas industry in New York State. The PSC believes the most effective way to establish a competitive gas market is for natural gas utilities to exit the merchant function over a three to seven year period. The PSC also established guidelines and began several proceedings related to implementing its policy statement. We are participating in each of the proceedings and continue to believe the competitive marketplace should decide who will be the suppliers of natural gas. We have not yet determined what effect the PSC Policy Statement will have on us.

In response to Order 888, the New York Power Pool submitted a compliance filing to the FERC. Power pool members submitted additional filings to the FERC in 1997 proposing the restructuring of the power pool by establishing a New York Independent System Operator, a Power Exchange and a New York State Reliability Council. The FERC conditionally authorized the formation of the system operator and reliability council in June 1998 and conditionally accepted the tariff and rates applicable to transmission service, and energy, capacity and ancillary services in January 1999. FERC also set certain issues for hearing and required additional filings to implement the restructuring proposal. Power pool members must file the necessary applications to transfer control of transmission facilities to the system operator. We are currently evaluating the FERC's conditional acceptance and are unable to predict its effect on our financial position or results of operations.

Electric Retail Access Program: Customers in certain sections of our service territory were eligible to choose their electricity supplier in mid-1998. All of our electricity customers in New York will be able to choose their electricity supplier by August 1, 1999. This is one of the most progressive retail access programs in the country.

Throughout the first phase and continuing after August 1, 1999, we are responsible for delivery of our customers' electricity on our transmission and distribution system. Rates charged for the use of our transmission system are subject to FERC approval, while rates for the use of our distribution system are subject to PSC approval. The PSC approved our distribution rates in January 1998. Our transmission rate case, which was filed with the FERC in March 1997, has not yet been approved.

Petition to the FERC on NUGs: We continue to seek ways to provide relief to our customers from the onerous NUG contracts that we were ordered to sign by the PSC. NUG power purchases totaled $323 million in 1998, and we estimate that those purchases will total $358 million in 1999 and $376 million in 2000 and in 2001, unless we are able to change those contracts.

We petitioned the FERC in 1995, asking for relief from having to pay approximately $2 billion more than our avoided costs for power purchased over the term of two NUG contracts. The FERC denied that petition and our subsequent request for a rehearing. We believe that the overpayments under the two contracts violate the Public Utility Regulatory Policies Act of 1978.

We petitioned the United States Court of Appeals for the District of Columbia in 1995 to review the FERC's decision. The Court of Appeals issued a decision in July 1997 stating that it lacked jurisdiction to rule on our appeal but that we may pursue our claim in the United States District Court.

We commenced an action in the United States District Court for the Northern District of New York in August 1997. The complaint asks the District Court to either reform the two NUG contracts by reducing the price we must pay for electricity under the contracts, or send the matter back to the FERC or to the PSC with direction that they modify such contracts. The complaint also seeks repayment of all monies paid above our avoided costs. The case is still pending before the District Court.

Electric Restructuring Plan: Our restructuring plan, which included a five-year electric rate price cap, was approved by the PSC, with minor modifications, in January 1998. It supersedes our previous three-year electric rate agreement, which was to expire on July 31, 1998.

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

Electric and natural gas utilities across the country continue to transform as competition evolves. To meet the challenges and seize the opportunities presented by competition, we, too, have changed. In April 1998 our shareholders overwhelmingly approved the formation of Energy East Corporation, our new holding company that became the parent of NYSEG. We are in the process of finalizing the sale of our coal-fired generation assets and are actively pursuing the sale of our 18% interest in Nine Mile Point nuclear generating unit No. 2. (See Sale of our Coal-fired Generation Assets below.) We are also expanding our products and services, including our energy distribution system in the Northeast.

Liquidity and Capital Resources

ELECTRIC BUSINESS

Our electric business consists of electric generation, transmission and distribution operations.

Sale of our Coal-fired Generation Assets: We placed our seven coal-fired stations and associated assets and liabilities up for auction in 1998. We accepted offers totaling $1.85 billion from The AES Corporation and Edison Mission Energy in August 1998 for those generation assets.

All proceeds, net of taxes and transaction costs, in excess of the net book value of the generation assets, less funded deferred taxes, will be used to write down our 18% investment in Nine Mile Point 2. This treatment is in accordance with our restructuring plan approved by the Public Service Commission of the State of New York in January 1998. There are a number of items such as depreciation, book value of inventories, taxes and the exact date of the closing that will affect the financial statements as we continue to precisely define the specific costs of the items included in the transactions. Any differences will affect the net proceeds. The net cash received from the sales will be used to repurchase common stock and continue expanding our products and services, including our energy distribution network in the Northeast.

The PSC approved the sales in November 1998 and the Federal Energy Regulatory Commission approved the sales in January 1999. We expect the sales to close by the end of the first quarter of 1999. We are developing strategies to satisfy our remaining energy requirements in New York after the coal-fired stations are sold. The power may be purchased at market prices that are different than the cost to generate the power from the coal-fired stations, which would increase or decrease our operating expenses. We expect to finalize these strategies before the stations are sold.

We use electricity contracts to manage our exposure to fluctuations in the cost of electricity. Such contracts allow us to fix margins on the majority of our retail and wholesale sales of electricity. The cost or benefit of electricity contracts is included in the cost of electricity purchased when the electricity is sold.

New York Power Pool Restructuring: The Federal Energy Regulatory Commission issued Orders 888 and 889 in 1996 to foster the development of competitive wholesale electricity markets by opening up transmission services and to address the resulting stranded costs. In subsequent orders, the FERC generally affirmed Orders 888 and 889. Various parties, including us, have appealed these orders in the United States Court of Appeals for the D.C. Circuit.

FINANCIAL REVIEW

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