LONG ISLAND LIGHTING COMPANY

ANNUAL REPORT 1994

VIEWPOINTS

The Long Island Lighting Company's 5,947 employees provide electric and gas service to more than 1 million customers in Nassau and Suffolk Counties and in the Rockaway Peninsula in Queens County. LILCO's service territory covers 1,230 square miles with a population of approximately 2.7 million people.

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VIEWPOINTS


Connecticut
New York
New Jersey
Bronx
Suffolk
Nassau
NYC
Queens
Brooklyn

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1994 Highlights

- Positive cash flow allowed the Company to meet all operating and construction requirements, as well as satisfy a portion of maturing debt.
- Earnings for common stock maintained at 1993 levels despite a higher number of shares outstanding and a lower allowed rate of return on common equity for the gas system.
- First common stock offering in ten years raised approximately $100 million.
- New record gas sendout of 585,227 dekatherms established in January.
- New record for customer energy use in a single month–1,975 gigawatt hours–established in July.
- Shoreham Nuclear Power Station decommissioning completed, pending final regulatory approval.

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1994 HIGHLIGHTS

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- New record for customer energy use in a single month–1,975 gigawatt hours–established in July.
- Shoreham Nuclear Power Station decommissioning completed, pending final regulatory approval.

TO OUR SHAREOWNERS

1994

LILCO achieved a financial milestone in 1994, generating sufficient cash from operations to meet all of its operating and construction requirements, in addition to satisfying a portion of its maturing debt obligations with cash on hand. The Company earned $2.15 per common share in 1994 on revenues of $3,067,307,000, the same level of earnings as in 1993, despite a higher number of common shares outstanding and a lower allowed rate of return on common equity for the gas system. The Company also maintained the quarterly common stock dividend at 44.5 cents per share.

LILCO's improved financial position enabled the Company to file with the Public Service Commission (PSC) a three-year electric rate plan requesting a base rate freeze through November 30, 1996, and a 4.3 percent increase beginning December 1, 1996. Even with the rate freeze, LILCO is in a stronger financial position today than was anticipated in the Shoreham settlement, due largely to implementing cost-cutting measures, refinancing higher cost debt, and purchasing fuel at lower costs. By holding base rates at current levels, the Company can better prepare for a more competitive market and aid the economic recovery of Long Island. The PSC indicated that it will act on the Company's pending rate request in April 1995.

◆ Competing Viewpoints

Discussions about introducing competition into the electric industry continued to dominate the industry, as policymakers nationwide confront the complex issues surrounding wholesale and retail wheeling. The financial markets reacted adversely to the discussions which, along with rising interest rates, caused the Dow Jones Utility Index to drop 20 percent.

In New York State, the PSC has been holding Competitive Opportunities Proceedings to evaluate the future structure of the electric industry. In Phase I of the proceedings, the PSC adopted guidelines for flexible electric rates under which utilities can negotiate individual contracts with large commercial/industrial customers to dissuade them from leaving the system. In Phase II, the Commission has taken up the larger issue of wholesale and retail wheeling.

◆ On The Homefront

In October 1994, Governor Cuomo proposed a state takeover of LILCO as part of his re-election campaign. The $21.50 per share proposal promised to cut electric rates by 10 percent or more by substituting tax-exempt securities for the Company's stocks and bonds, and by eliminating federal income tax. Your Board of Directors had authorized management to commence discussions with the state to pursue their offer, but since Cuomo's defeat in the November election, the takeover plan has not been pursued by Governor Pataki's administration.

Energy costs continue to be a political issue on Long Island, with local public officials offering various plans to lower rates. Suffolk County has indicated that it will seek permission from the Federal Energy Regulatory Commission to municipalize the electric system in the county. Nassau County has filed a petition with the PSC to allow retail competition in its county. We will vigorously oppose both proposals because we believe neither would result in lower rates for all LILCO customers.

Proposals like these underscore the need for a structure that would allow for competition to be implemented in a manner that is fair to both residential and commercial ratepayers and to shareowners. To that end, we encourage all utility investors to make their viewpoints known through shareowner organizations or directly to elected officials.

◆ Working Our Strengths

To hold down rates and position the Company for a more competitive market, it has been necessary to vigorously cut costs. LILCO has saved $100 million in interest annually through aggressive refinancing of higher cost debt and preferred stock, and an additional $73 million in 1994 by combining off-system power purchases with burning natural gas in our power plants. In the last few years, we reduced our workforce by 600 employees through attrition and project an additional reduction of 250 employees by the end of 1995. And since 1989, we have saved more than $130 million by implementing cost containment programs, overtime reductions, managed health care and improvements in power plant reliability.

In addition to reducing costs, we are working hard to retain revenues. We established a major accounts organization focusing on our largest customers, especially those with options for alternative energy sources. We are working to expand the Island's economy, which had suffered a recession following the defense cutbacks a few years ago. Through our efforts, 169 companies and 9,300 jobs have come to or expanded on Long Island. We also embarked on an innovative program with the state to retain and revitalize the region's manufacturing industry, involving 81 companies and more than 21,000 jobs.

In addition, LILCO's Research & Development Initiative continues to take the unique research and technology assets of the region and put them to work at LILCO. By partnering Long Island industries in creating new technologies for utility use, we are able to improve our service and strengthen the local economy.

In stimulating the region's economy, we are seeking to hold down rates by spreading our fixed costs over a larger customer base. Although the region has not fully recovered from the recession, we are confident that Long Island will rebound because of its proximity to New York City and international airports, its highly skilled workers, and its growing technology industries.

◆ Redefining Our Business

LILCO is implementing new strategies to respond to Long Island's energy needs. On the electric side of the business, we are exploring energy-efficient technologies that increase electric load while allowing customers to decrease overall energy costs. On the gas side, we have targeted expanded use of natural gas in homes and businesses that already have a gas service, allowing the Company to increase sales with minimal capital expenditure. Despite a significant decrease in fuel oil prices, we have continued to add customers to the gas system and see significant long-range opportunities there.

As always, our focus is providing unparalleled service to customers and excellent value to shareowners. Despite changes in the industry, our commitment to that goal will never change. On behalf of LILCO's Board of Directors and its employees, I would like to thank you for your confidence in our ability to keep that commitment.

Sincerely,

W. J. Catacosinos

William J. Catacosinos

Chairman, President and Chief Executive Officer

VIEWPOINTS

The utility industry is heading in a new direction toward a market in which the [illegible] will not be defined by simple generation but instead by its customer service. This, in short, is [illegible] goals. As we position our company to meet the challenges of this rapidly changing marketplace, it is crucial that we take time to evaluate our strengths, and identify areas for improvement. To this end, we invited experts from various communities we serve to look at [illegible] performance in [illegible] and provide insights into the progress we have made, as well as the work yet to be done.


CHANGE


VALUE


GROWTH

While new forms of competition are being debated, utilities have been purchasing low cost power through the power pool and two-party transactions. LILCO's system dispatchers continually compare LILCO's cost of generation against outside power to provide electric service at the lowest possible cost. The Company's dedication to cost-effectiveness also includes using the most economic mix of fuels and generating units within LILCO's system.

In 1994, combined savings from off-system power purchases and burning natural gas in our power plants totaled more than $73 million.

Dr. William W. Hogan
Professor of Public Policy and Management, Harvard University

EMERGING COMPETITION

"There's tremendous pressure in New York for electric competition to move ahead rapidly. The rhetoric suggests that we must have competition because electric prices are 'suddenly' much higher here than the national average. But when you look at the cost of electricity in real terms for industry in New York, the rhetoric is not based in fact. What actually is different is that now there is the opportunity to buy from other sources through retail competition. Customers want to buy elsewhere and avoid paying utility historical costs.

The trick is to design a system that allows for competition at the margin, but doesn't compromise the ability to collect costs that have been prudently incurred. That's not impossible. What is impossible is to design a system that produces dramatic reductions in rates quickly. It's the very nature of the electricity industry that a large portion of the costs are historical costs and nothing will reduce them. You can either have dramatic reductions in rates or honor the commitment to collect prudently incurred costs, but you cannot have both.

In a sense, LILCO is in a better position to handle competition than some other utilities. There are a limited number of transmission cables connecting Long Island to the Northeast power grid, through which competitive power would have to be delivered. Since much of the capacity on these cables is being utilized now, only so much outside power can be brought in for off-system sales. LILCO is also 'protected' in that the Company has fewer large customers than many other utilities, and these large customers are the ones that are most likely to have the ability to leave the system. And, unlike other utilities, LILCO has reached an agreement with the state on its sizeable regulatory asset. Other utilities have yet to complete this process.

To equitably implement competition, regulators need to separate the historical costs from the actual costs for generating electricity. When competitors come up against the real costs at the margin – in LILCO's case, 3.4 cents (kwh) – suddenly LILCO is looking pretty competitive."

Ernest S. Liu
Partner, Goldman Sachs

FINANCIAL HEALTH

"By far the biggest challenge facing utilities today is to adjust to competition while protecting their financial health. The underlying issue is that utilities have always been heavily regulated. Within that environment, they constructed electric systems, obtaining capital with regulatory assurances that they would be able to recover prudent costs. Today, there are less expensive technologies available to non-utility generators that, along with other factors, allow them to offer lower prices to consumers. Utilities are left with immense investments, undertaken to meet regulatory obligations, that are not yet fully amortized.

The stock market is worried about utilities being able to fully recover historical assets and still pay a stream of dividends to stockholders. It's a question of honoring commitments. And in LILCO's case, the question goes specifically to the Shoreham agreement. Investors are asking, with the recent change in administration and emphasis on promoting competition, does New York State intend to honor the future recovery of this asset?

The market is looking for assurances that the agreement between LILCO and the state is one which all future administrations will honor. Certainly LILCO has lived up to its part of the bargain. The Company has worked hard to improve its financial standing, using the improved cash flow we have seen in recent years to retire and refinance high cost debt. They have decreased their head count, improved their balance sheet by thickening their equity base, and maintained their dividend, which is essential to retaining credibility with the capital market.

The worst enemy of the investor is uncertainty. The financial community recognizes that LILCO has made much faster progress in improving its operations and cash flow, but people need to see some sign of good faith on the part of the state. I believe if we get that sign, LILCO stock will show some rebound and that, in turn, will enable the Company to continue to improve its balance sheet."

Despite external forces that impacted the value of utility stocks nationwide, LILCO's financial health continued to improve in 1994. Earnings and common stock dividends were maintained at 1993 levels and, for the first time in ten years, the Company offered shares of common stock, raising approximately $100 million.

This offering, combined with satisfying a portion of maturing debt with cash on hand, allowed LILCO to reduce its debt ratio from 65 percent in 1993 to 62.5 percent by the end of 1994.

Since 1991, LILCO has played a key role in the Long Island Partnership, a coalition of business, education, and government working together to stimulate the region's economy. Through the expansion of the Company's own economic development staff and the investment of more than $2 million in the Partnership effort, LILCO has been instrumental in attracting, retaining or expanding more than 250 companies, and a total of 30,000 jobs on Long Island.

Roslyn D. Goldmacher
Executive Director, Long Island Development Corporation

REGIONAL ADVANCES

"In the 1980s, the Long Island region was prosperous and the economy essentially drove itself. The changes of the 1990s demonstrate, however, the importance of aggressive economic development efforts even in a healthy economy.

LILCO has realized it needs to be a leader in this area. Nationwide, utilities have traditionally played the key role in economic development for their communities. The local utility has a unique link to every business and every consumer. It is tied to the community. If it is in anyone's interest to keep the region vibrant and healthy, it's in the utility's interest.

LILCO's involvement in regional economic development in the last few years has been very beneficial for the area's stability and growth. Long Island has many layers of government and with so many players in one pot, someone must take the lead to provide a cohesive, effective effort.

LILCO has created a formal method for coordinating economic development resources in the region through the New Long Island Partnership. It provides a single point-of-contact where businesses can go and say, 'I need help, how can you help me?' and the right resources are brought to the table. And LILCO has done this without creating additional financial burden on those resources. LILCO has effectively allowed the economic development agencies to extend their outreach without spending more money.

The 'hand-holding' LILCO provides has resulted in many companies making the decision to stay, or expand, or come to Long Island. It has made the process more user-friendly. In economic development, that's the whole idea.

LILCO's involvement in economic development efforts benefits ratepayers and stockholders, as well. Ultimately, if the economy thrives, so will the utility. Rates remain stable and dividends get paid. So it's not just a matter of a moral obligation to the community. Good business is good business. It's as simple as that."

Roslyn D. Goldmacher

Dr. Philip F. Palmedo
President, Long Island Research Institute

RESEARCH AND DEVELOPMENT

"The general public, even the corporate and investment worlds, have not yet come to appreciate the strength in high-tech research and development that exists on Long Island. Many regions of the country have strength in R&D, but few have the concentrated, diversified strengths we have here. The fact that Long Island has a major strength not in one narrow area but in many suggests that synergistic technological combinations will emerge here.

Unfortunately, Long Island has lacked a coordinated regional effort to capitalize on these strengths properly. When you think of the regions across the country that have excelled in technology-based economic development, they are not necessarily those with the best research, but those capable of translating that research into commercial activity.

Somebody has to have the imagination to envision the route to concrete commercial uses of innovative research; to move technology from creator to user. That's the basic philosophy of the Long Island Research Institute. We look at technologies and build bridges out to the potential users. That's also the philosophy behind LILCO's R&D Initiative, and I am a great supporter of their efforts because they are working to build bridges from their end.

The process of converting technologies from a research stage to practical application requires the ability to evaluate a technology for competition with others and an understanding of the appropriate business strategy to move that technology into industry. But the really critical component is understanding the user's point of view. When you have a company like LILCO, a major user participating in the process, that focuses and expedites the entire effort.

The region would greatly benefit if other industry sectors would emulate LILCO's Initiative and would energize applied research and development to address the important needs and opportunities in their specific fields."

LILCO's Research & Development Initiative is currently entering its fourth successful year. Created to provide LILCO with innovative technologies needed to compete in the consumer-driven service industry of the 90s, the Initiative has awarded more than $10.7 million to 45 Long Island technical institutions for 84 projects since 1991. Matching research talent with industrial resources has helped stimulate regional economic growth while helping us improve the ways we produce, deliver and conserve electricity and natural gas.

INNOVATION


COMMUNITY

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SOCIAL INVOLVEMENT

"I grew up on Long Island in the generation following World War II, a very prosperous time for our region. Most families then were very traditional, with Dad going to work and Mom staying home to take care of the kids. Families had that luxury in those days. But today, we're in very different times. We're in different times in terms of government – with serious cutbacks in services; in terms of jobs – with the declining defense industry creating unemployment problems, and in terms of family – there's a lot of social and economic pressure that makes it difficult for people to function as a family.

In the midst of these changes, there is a temptation to say that the problems are so great, nothing can be done. I don't agree. Problems are always solved one at a time. They're always solved looking into the eyes of individual people.

The challenge for a corporation like LILCO is to continue to care about the problems affecting the people of Long Island. Why? Because any corporation is really a composite of people. The individuals who come to work at LILCO are not only workers, they are part of the community. For the corporation to understand them, it must be part of the community, too.

If a company grows and makes its money on Long Island and does not give back to the community, its people become disenchanted. But if it engages its people in a dialogue, lets them know it cares about this Island, that can make all the difference.

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The challenge to corporations is to be responsive. It isn't a question of whether to be involved, but how to be involved. We're all part of the human story. We need to be connected."

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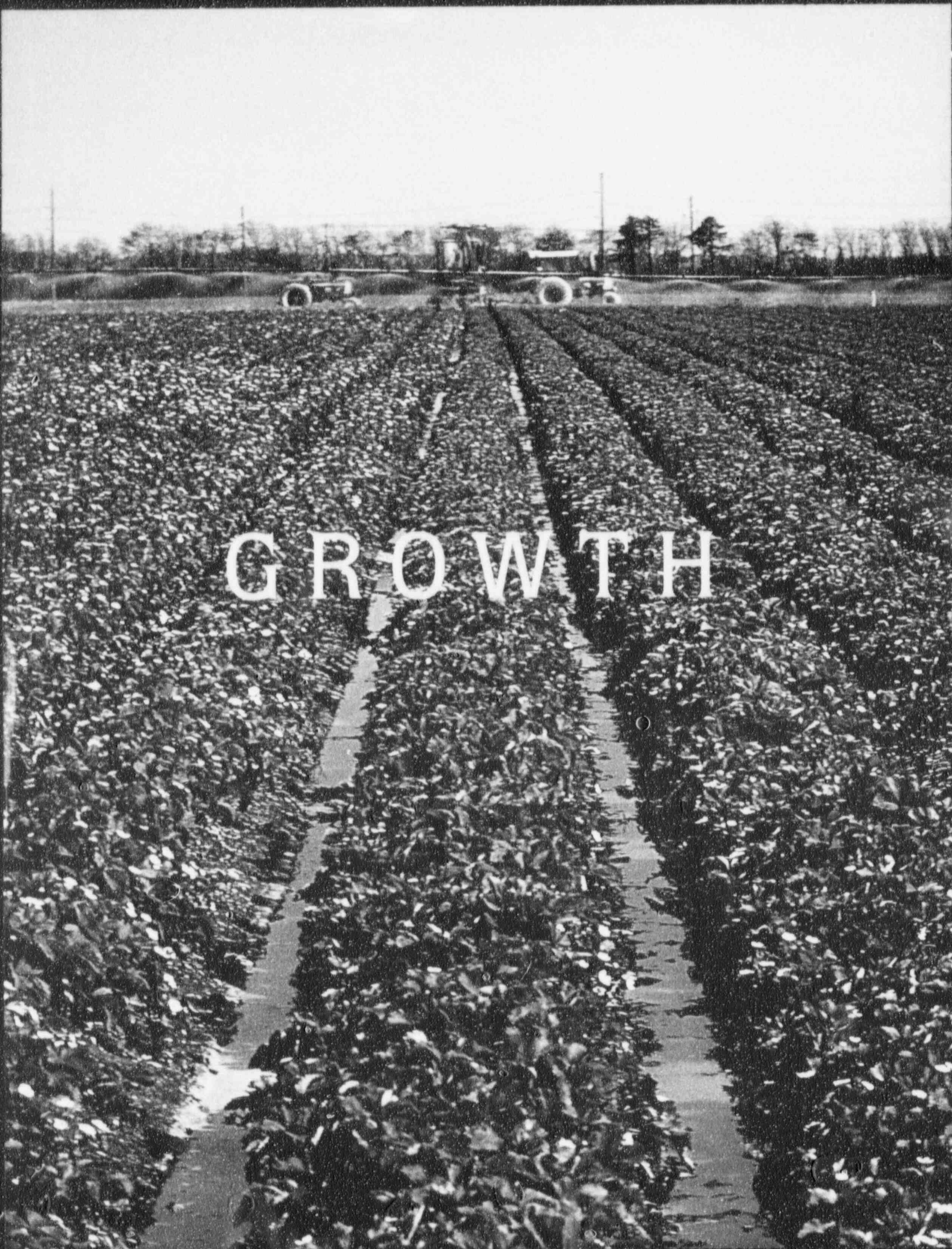
CHANGE


NEW YORK STOCK EXCHANGE
VALUE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FINANCIAL CONTENTS

Overview

In 1994, the Company reached a milestone by generating sufficient cash from operations to meet all of its operating and construction requirements in addition to satisfying a portion of its maturing debt obligations with cash on hand. The positive cash flow resulted, in part, from the collection of deferred revenues associated with the Rate Moderation Component (RMC) and the Long Island Lighting Company Ratemaking and Performance Plan, and the Company's continued efforts to maximize operating efficiencies while reducing operating costs.

Since 1989, the Company has received six electric rate increases and has experienced lower than anticipated fuel costs, financing costs and production expenses, all of which have helped to improve cash flow, which in turn, has improved the Company's financial health. This improved financial health has enabled the Company to file with the Public Service Commission of the State of New York (PSC) on December 31, 1993, a three year electric rate plan (Electric Rate Plan) requesting that base electric rates be frozen through November 30, 1996, and that overall electric rates increase 4.3% beginning December 1, 1996. The Electric Rate Plan, as designed, will help to better position the Company to meet existing and anticipated competitive challenges in addition to assisting the economic recovery of Long Island.

Three Administrative Law Judges (ALJs) issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposal to freeze base electric rates for the first year, and implied that base rates could remain frozen for the second year as well. The ALJs encouraged the Company and other intervening parties in the proceeding to negotiate a settlement regarding the third year of the Company's Electric Rate Plan. The Company, the PSC and other parties to this proceeding continue to negotiate toward a three year rate settlement. The Company believes that a three year rate settlement is in the best interest of shareowners and ratepayers.

Other significant achievements during 1994 included:

- The Company maintained the same level of earnings per common share in 1994 as in 1993, despite a lower allowed return on common equity for the gas business and the issuance of 6.1 million shares of common stock during 1994;

- The public offering of 5.1 million shares of the Company's common stock, for the first time in nearly ten years, raising approximately $100 million. This offering, combined with the satisfaction of a portion of maturing debt with cash on hand, has resulted in the reduction in the Company's debt ratio to 62.5% at December 31, 1994 from 65.0% at December 31, 1993;

- The continuation of the Company's quarterly common stock dividend rate at 44½ cents per share;

- The reduction of the Company's average coupon rate on its outstanding long-term debt to 7.9% as a result of the Company's refinancing activities. The refinancing of a significant amount of the Company's long-term debt and preferred stock, over the past several years, has resulted in annual cash savings of approximately $100 million;

- The reduction of the RMC balance from $610 million at December 31, 1993 to $463 million at December 31, 1994. This reduction resulted, in part, from current year revenues under the Rate Moderation Agreement exceeding revenues that were required in 1994 under conventional ratemaking;

- The completion, pending final regulatory approval, of the decommissioning of the Shoreham Nuclear Power Station, including the removal and transportation of Shoreham's fuel to another utility;

- The receipt of a gas rate increase effective December 1, 1994, which is the second of three gas rate increases under a three-year settlement between the Company and the PSC which provides for annual rate increases of 4.7%, 3.8% and 2.8% for the rate years beginning December 1, 1993, 1994 and 1995, respectively;

- The addition of over 8,500 new gas space heating customers, resulting from the continuation of the Company's gas expansion program;

- The establishment of a record maximum day gas sendout of 585,227 dekatherms on January 19, 1994.

In addition, in 1994, the Company received an invitation at the request of the former Governor of New York State, from the chief executives of the New York Power Authority and the Long Island Power Authority, for the Company to enter into negotiations with them in a proposal to convert the Company into a public power utility. The new Governor empaneled a task force to study the "takeover" proposal. While the task force did not make its recommendation public, published reports in local newspapers indicate that the task force recommended to reject the proposal.

Liquidity

At December 31, 1994, the Company's cash and cash equivalents amounted to approximately $185 million, compared to $249 million at December 31, 1993. The decrease in cash and cash equivalents reflects the Company's strategy of applying available cash balances toward the satisfaction of maturing debt.

The Company has available for its use a $300 million revolving line of credit through October 1, 1995, provided by its 1989 Revolving Credit Agreement (1989 RCA). At December 31, 1994, no amounts were outstanding under the 1989 RCA. This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories. The 1989 RCA may be extended for one year periods upon the acceptance by the lending banks of a request by the Company. The Company's request must be delivered to the lending banks prior to April 1 of each year. In 1995, the Company intends to request such an extension. For a further discussion of the 1989 RCA, see Note 7 of Notes to Financial Statements.

Capitalization

The Company's capitalization, including current maturities of long-term debt and current redemption requirements of preferred stock, at December 31, 1994, was approximately $8.3 billion, compared to $8.4 billion at December 31, 1993. At December 31, 1994 and 1993, the Company's capitalization ratios were as follows:

	1994	*1993*
Long-term debt	**62.5%**	65.0%
Preferred stock	**8.6**	8.5
Common shareowners' equity	**28.9**	26.5
	100.0%	100.0%

The Company is committed to reducing its debt ratio. To achieve this goal, the Company intends to continue reducing debt with cash generated from operations and intends to issue common or preferred stock if market conditions prove favorable. With this commitment in mind, the Company issued 5.1 million shares of common stock in 1994, marking the first time in approximately ten years that the Company issued common equity, other than through its Automatic Dividend Reinvestment Plan, its Employee Stock Purchase Plan or through the conversion of Series I Preferred Stock.

In 1994, the Company applied the net proceeds from the sale of the 5.1 million shares of common stock and the issuance of $285 million of General and Refunding Bonds (G&R Bonds) toward the repayment, at maturity, of $400 million of debentures and the redemption of $30 million and $5 million of debentures that had been scheduled to mature in 1999 and 2019, respectively. Cash from operations provided the balance of funds needed to retire/redeem this debt and to retire $25 million of First Mortgage Bonds, which matured in June 1994. In addition, in November 1994 the Company used cash on hand to satisfy the payment of $175 million of maturing debentures.

The Company's need to access the financial markets to provide additional capital or to refinance its maturing debt has diminished compared to prior years. The Company intends to use cash generated from operations to satisfy the payment of $25 million of First Mortgage Bonds maturing on June 1, 1995. With respect to the repayment of $455 million and $286 million of debt maturing in 1996 and 1997, respectively, the Company intends to use cash generated from operations to the maximum extent practicable. The balance of funds necessary to satisfy maturing debt obligations in 1996 and 1997 will be obtained through the issuance of either debt or equity securities, or some combination thereof.

Despite improving financial indicia, the Company's securities, which are rated by Standard and Poor's Corporation (S&P), Moody's Investors Service (Moody's), Fitch Investors Service, L.P. (Fitch) and Duff and Phelps, Inc. (D&P), have been downgraded by certain rating agencies over the past eighteen months. In June 1994, Moody's lowered the credit ratings of the Company reflecting Moody's expectations that the Company's high tariff rates will intensify business risk in an increasingly competitive environment. Recently, S&P placed its ratings on the Company's securities on "Credit Watch with negative implications," Fitch changed its credit trends to "declining" and Moody's placed the Company's credit ratings under review for a possible downgrade reflecting their respective concerns about the regulatory environment in New York State.

At December 31, 1994, the ratings for each of the Company's principal securities were as follows:

	S&P	*Moody's*	*Fitch*	*D&P*
First Mortgage Bonds	**BBB–**	**Baa3**	**BBB**	**BBB**
G&R Bonds	**BBB–**	**Baa3**	**BBB**	**BBB**
Debentures	BB+	Ba1	**BBB–**	BB+
Preferred Stock	BB+	ba1	**BBB–**	BB
Minimum Investment Grade	**BBB–**	**Baa3**	**BBB–**	**BBB–**

Bold face indicates securities that meet or exceed minimum investment grade.

The Company's Authority Financing Notes (Notes), some of which are secured by letters of credit, are rated by certain of the rating agencies. The ratings on the Notes secured by letters of credit reflect the ratings of the institutions issuing the letters of credit, and not that of the Company.

Capital Requirements and Capital Provided

Capital requirements and capital provided for 1994 and 1993 were as follows:

	1994	1993
	(In millions of dollars)	
Capital Requirements		
Construction		
Electric	**$ 135**	$ 136
Gas	**119**	125
Common	**23**	41
Total Construction	**277**	302
Refundings and Dividends		
Long-term debt	**635**	960
Preferred stock	**5**	206
Common stock dividends	**205**	196
Preferred stock dividends	**53**	57
Redemption costs	**2**	15
Total Refundings and Dividends	**900**	1,434
Shoreham post settlement costs	**167**	207
Total Capital Requirements	**$ 1,344**	$ 1,943
Capital Provided		
Cash generated from operations	**$ 836**	$ 582
Long-term debt issued	**331**	1,090
Common stock issued	**118**	14
Preferred stock issued	**—**	202
Financing costs	**(4)**	(6)
Decrease in cash	**63**	61
Total Capital Provided	**$ 1,344**	$ 1,943

For further information, see the Statement of Cash Flows.

Given the Company's current electric load forecast and the availability of electricity provided by the Company's generating facilities and by purchases of power from others, the Company forecasts that it will not need any new generating facilities until beyond the year 2000. As a result, the Company does not forecast any need for external financing for the construction of generating facilities during this period. With respect to financing other capital additions to plant, the Company estimates that cash generated from operations will be sufficient to meet any such requirements in 1995.

For 1995, total capital requirements (excluding common stock dividends) are estimated at $431 million, of which maturing debt is $25 million, additions to plant are $277 million, preferred stock dividends are $53 million, preferred stock sinking funds are $5 million and Shoreham post settlement costs are $71 million, including $58 million for payments in lieu of taxes.

Rate Matters

Electric

In conjunction with the 1989 Settlement, the PSC agreed to the recognition of a regulatory asset known as the Financial Resource Asset (FRA). The FRA consists of two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC), discussed in Note 1 of Notes to Financial Statements. The Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides for the full recovery of the FRA.

The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis that began July 1, 1989. The RMC had provided the Company with a substantial amount of non-cash earnings since the effective date of the 1989 Settlement through December 31, 1992, as the revenues provided under the RMA were less than the revenues required under conventional ratemaking. During 1993, however, as the revenues provided under the RMA began to exceed the revenues that would have been provided under conventional ratemaking, the RMC balance began to decline.

Pursuant to the 1989 Settlement, the Company has received six electric rate increases as contemplated by the RMA. In November 1991, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) which provided annual electric rate increases of 4.15%, 4.1% and 4.0% effective December 1, 1991, 1992 and 1993, respectively. The LRPP provided for an allowed return on common equity from electric operations of 11.6% for each of the three rate years.

The LRPP was designed to be consistent with the RMA's long-term goals. One principal objective of the LRPP is to reassign risk so that the Company assumes the responsibility for risks within the control of management, whereas risks largely beyond the control of management would be assumed by the ratepayers.

One of the major components of the LRPP provides for a revenue reconciliation mechanism that eliminates the impact on earnings of experiencing electric sales that are above or below the LRPP forecast by providing a fixed annual net margin level (defined as sales revenues, net of fuel and gross receipts taxes) that the Company receives under the LRPP.

The LRPP allows the Company to earn for each rate year up to 60 additional basis points, or forfeit up to 38 basis points, of the allowed return on common equity as a result of the Company's performance within certain incentive and/or penalty programs. These programs consist of a customer service performance plan, a demand side management (DSM) program, a time-of-use program, a partial pass through fuel cost incentive plan, and effective December 1, 1993, an electric transmission and distribution reliability plan. Based upon the Company's performance within these programs, the Company earned a total of 50 and 49 basis points, or approximately $9.2 million, net of tax effects, for each of the rate years ended November 30, 1994, and 1993. For the rate year ended November 30, 1992, the Company earned approximately $4.3 million, net of tax effects, for its performance in these programs.

The LRPP contains a mechanism whereby earnings in excess of the allowed return on common equity of 11.6%, excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners. The Company earned $8.9 million and $21.4 million, net of tax effects, for the rate years ended November 30, 1993 and 1992, respectively, in excess of its allowed return on common equity which was shared equally between ratepayers (by a reduction to the RMC) and shareowners. For the rate year ended November 30, 1994, the Company did not earn in excess of its allowed return on common equity.

In December 1993, the Company filed a three year Electric Rate Plan with the PSC for the period beginning December 1, 1994 that minimizes future electric rate increases while retaining consistency with the RMA's objective of the restoration of the Company's financial health. The Electric Rate Plan requests an allowed return on common equity of 11.0%, and provides for base rates to be frozen in years one and two and an overall rate increase of 4.3% in the third year. Although base electric rates would be frozen during the first two years of the Electric Rate Plan, annual rate increases of approximately 1% are expected to result from the operation of the Company's fuel cost adjustment (FCA) clause. The FCA captures, among other things, amounts to be recovered from or refunded to ratepayers in excess of $15 million, which result from the reconciliation of revenues, certain expenses and earned performance incentive components, under the LRPP, discussed in Note 3 of Notes to Financial Statements.

The Company's Electric Rate Plan reflects four underlying objectives: (i) to limit the balance of the RMC during the three year period to no more than its 1992 peak balance of $652 million; (ii) to recover the RMC within the time frame established in the 1989 Settlement; (iii) to minimize, beginning in the third year of the Electric Rate Plan, the final three rate increases contemplated in the 1989 Settlement that follow the two year rate freeze period; and (iv) to continue the Company's gradual return to financial health.

The Electric Rate Plan provides for, with some modifications, the continuation of the LRPP revenue and expense reconciliations and performance incentives. The Electric Rate Plan includes the annual reconciliation of certain expenses for property taxes, interest costs, DSM costs and the deferral and amortization of certain costs for enhanced reliability. The Company would be allowed to earn for each of the three rate years under the Electric Rate Plan up to 50 additional basis points, excluding incentives under the DSM program, or forfeit up to 47 basis points of the allowed return on common equity of 11.0% as a result of the Company's performance within certain performance programs. These programs consist of a customer service program, a partial pass through fuel cost incentive plan, a DSM program and an electric transmission and distribution reliability plan.

The Company's Electric Rate Plan provides for lower annual electric rate increases than originally anticipated under the 1989 Settlement. However, as a result of changes in certain assumptions upon which the RMA was based, their impact on the RMC and the Company's plans to reduce DSM, operations and maintenance and capital expenditures, the Company has determined that the overall objectives of the RMA can be met under the Electric Rate Plan. As a result of lower than originally anticipated inflation, interest costs, property taxes, fuel costs and return on common equity allowed by the PSC, the RMC, which originally had been anticipated to peak at $1.2 billion in 1994, peaked at $652 million in 1992. With the exception of a projected increase in 1995 and 1996, which is not now anticipated to cause the RMC to increase above its $652 million peak, the RMC is expected to decline until it is fully amortized.

Under the Electric Rate Plan, the recovery of the RMC would be extended, if necessary, for an additional period of not more than three years beyond the approximate ten year period envisioned in the RMA. The actual length of the RMC extension will depend upon the extent to which the assumptions underlying the Electric Rate Plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years.

The Staff of the PSC (Staff) and other intervening parties filed testimony in response to the Company's Electric Rate Plan. Staff concurs with the Company's proposal for an 11.0% return on common equity in each of the three years, and has reaffirmed its commitment to the principals of the RMA, including the full recovery of the RMC within the time frame established by the RMA. However, Staff has recommended an overall zero percent rate increase for the first two years, contrasted with the Company's proposal for a base rate freeze with FCA adjustments of approximately 1% in years one and two, as described above. Staff did not make a recommendation for the level of rate relief in the third year.

In September 1994, three ALJs of the PSC issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposed 11.0% return on common equity and its proposal to freeze base electric rates for the first rate year. While no explicit recommendation was made concerning the second year, the recommended decision implied that base rates could remain frozen for the second rate year as well.

With respect to the third rate year beginning December 1, 1996, the ALJs determined that it was not appropriate for them to issue a recommendation since, in their opinion, the Company's revenue requirements for the third rate year could not be precisely determined at this time. Alternatively, the ALJs encouraged the Company and other parties in the proceeding to negotiate a settlement concerning any rate increase for the third rate year.

The PSC had been expected to issue a final order on the Company's Electric Rate Plan before November 29, 1994, the date that the statutory suspension period was scheduled to terminate. However, in order to accommodate further settlement negotiations in the proceeding, the Company has requested extensions through April 1995, which were granted by the PSC. The Company's offers to extend the suspension period were conditioned upon the continuation of the current LRPP rate mechanisms. Although the ultimate outcome of the Electric Rate Plan cannot be predicted, the Company expects that any PSC order will be consistent with the provisions of the RMA respecting the recovery of the FRA and other 1989 Settlement deferred charges.

Gas

In December 1993, the PSC approved a three year gas rate settlement, between the Company and the Staff of the PSC. The gas rate settlement provides that the Company receive, for each of the rate years beginning December 1, 1993, 1994 and 1995, annual gas rate increases of 4.7%, 3.8% and 2.8%, respectively. An allowed return on common equity of 10.1% was used in the determination of the revenue requirements for the gas rate settlement. The gas rate decision provides that earnings in excess of a 10.6% return on common equity in any of the three rate years covered by the settlement be shared equally between the Company's firm gas customers and its shareowners. For the rate year ended November 30, 1994, the Company earned $9.2 million, net of tax effects, in excess of the 10.6% return on common equity. The firm gas customers' portion of these excess earnings amounting to $4.6 million, net of tax effects, has been deferred until its final disposition is determined by the PSC.

Environment

During 1994, the Company spent approximately $6.4 million in order to comply with the 1990 amendments to the Federal Clean Air Act (Act). These expenditures were necessary to meet continuous emissions monitoring requirements and Phase I nitrogen oxide (NOx) reduction requirements under the Act.

The Company expects that it will have to expend approximately $1 million in 1995 to meet continuous emission monitoring requirements and to meet Phase I NOx reduction requirements. In order to generate 210 tons of NOx reduction credits already under contract for sale to a third party, the Company anticipates spending $2.5 million in 1995 and $1.9 million in 1996 for earlier than required NOx reduction systems. Subject to requirements that are expected to be promulgated in forthcoming regulations, the Company estimates that it may be required to spend an additional $80 million (net of NOx credit sales) by 2003 to meet Phase II and Phase III NOx reduction requirements. In an effort to minimize costs associated with anticipated NOx reduction requirements, the Company is engaged in a $7 million research and development project along with several co-funding organizations to demonstrate an innovative NOx reduction technology at its E.F. Barrett Power Station. The Company is committed to fund $3.6 million of the project costs. Through 1994, approximately $5 million has been expended by all of the co-funders. It is anticipated that the remaining $2 million will be spent in 1995. In addition, the Company estimates that it may be required to spend approximately $24 million by 1999 to meet potential requirements for the control of hazardous air pollutants from power plants. The Company believes that all of the above mentioned costs will be recoverable through rates.

The New York State Department of Environmental Conservation has indicated to New York State utilities that it may require all such utilities to investigate and, where necessary, remediate their former manufactured gas plant sites. The Company is the owner of six pieces of property on which the Company or certain of its predecessor companies produced manufactured gas. Although the exact amount of the Company's clean-up costs cannot yet be determined, based on the findings of investigations at two of these six sites, preliminary estimates indicate that it will cost approximately $35 million to clean-up all of these sites over the next five to ten years. Accordingly, the Company has recorded a $35 million liability and a corresponding regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these clean-up costs. However, the Company is unable to predict the amount of insurance recovery, if any, that it may obtain.

The Company has been notified by the Environmental Protection Agency (EPA) that it is one of many potentially responsible parties (PRPs) that may be liable for the remediation of three contaminated licensed treatment, storage and disposal sites. At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have completed a Remedial Investigation and Feasibility Study which is currently being reviewed by the EPA. The level of remediation required will be determined when the EPA issues its decision, currently expected in May 1995. The Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site. The Company believes that any cost incurred to remediate this site will be recoverable through rates.

With respect to the other two sites, which are located in Kansas City, Kansas and Kansas City, Missouri, the Company is investigating allegations that it had previously stored or made agreements for the disposal of polychlorinated biphenyls (PCBs) or items containing PCBs at these sites. The Company is currently unable to determine its share of the cost to remediate these sites or the impact, if any, on the Company's financial position. The Company believes that any cost incurred to remediate these sites will be recoverable through rates.

NYPA and LIPA Proposal

At the request of the then Governor of the State of New York, on October 13, 1994 the chief executives of the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA) invited the Company to enter into negotiations with them regarding a proposal to convert the Company into a public power utility. Under the proposal, the two state authorities contemplated a business combination in which holders of the Company's common stock would receive $21.50 in cash for each outstanding share of the Company's common stock. NYPA and LIPA indicated that the completion of this transaction would be subject to, among other things, the availability of tax-exempt financing sufficient to complete the transaction and the verification by NYPA and LIPA that the transaction would result in rate reductions in excess of 10%. The Company's Board of Directors has authorized the Company to enter into discussions with NYPA and LIPA to explore the proposal in greater detail, but no such discussions have been held.

The new Governor of the State of New York had empaneled a task force to study the takeover proposal. While the task force did not make its recommendation public, published reports in local newspapers indicate that the task force recommended to reject the proposal.

Competitive Environment

Significant changes are taking place in the business and regulatory environment in which electric utilities operate. In response, the Company, like utilities across the nation, is actively involved with federal and State agencies in evaluating what type of competition would best serve both customers and investors. The Company has also undertaken a review of its current operations, seeking to shape those operations to best meet the challenges of a competitive environment. As federal legislators and regulators continue pursuing a policy of evaluating competition in the electric utility industry, state regulators are addressing the many complex and politically sensitive issues which will affect the cost and reliability of service to customers in their jurisdictions. The focus on electric competition has also prompted municipalities, school districts and certain other customers to seek permission to buy energy elsewhere.

The Electric Industry — Federal Regulatory Issues

As a result of Congress' passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the National Energy Policy Act of 1992 (NEPA), the once monopolistic electric utility industry now faces competition.

PURPA's goal was to reduce the United States' dependence on foreign oil, encourage energy conservation and promote diversification of fuel supply. Accordingly, PURPA provided for the development of a new class of electric generators which rely on either cogeneration technology or alternate fuels. The utilities are obligated under PURPA to purchase the electric output of certain of these new generators, which are known as qualified facilities (QFs).

NEPA sought to increase economic efficiency in the creation and distribution of power by relaxing restrictions on the entry of new competitors to the wholesale electric power market (i.e., sales to an entity for resale to the ultimate consumer). NEPA does so by creating exempt wholesale generators that can sell power in wholesale markets without the regulatory constraints placed on generators such as the Company. NEPA also expanded the Federal Energy Regulatory Commission (FERC)'s authority to grant access to utility transmission systems to all parties who seek wholesale wheeling for wholesale competition. Significant issues associated with the removal of wholesale transmission system access restrictions have yet to be resolved and the potential impact on the Company's financial position cannot yet be determined.

FERC is in the process of setting policy which will largely determine how wholesale competition will be implemented. FERC has recently declared that utilities must provide wholesale wheeling to others that is comparable to the service utilities provide themselves. The policy will be tested and further defined in individual proceedings. In addition, FERC has issued policy statements concerning regional transmission groups, transmission information requirements and "good faith" requests for service and transmission pricing. FERC is also initiating proceedings to address issues relating to stranded assets and power pooling. Utilities, including the Company, and other interested parties are actively involved in these proceedings.

Major issues are arising as the industry and government contemplate the move toward a more market-driven environment. These issues include: the impact of competition on customers who are unable to or who have chosen not to avail themselves of competition options; the ability of utility investors to continue to receive a return of and a reasonable return on their investments; the effect on service quality and reliability; comparability of service; the parameters of regulatory jurisdiction; the relative efficiency of competitors; the effects of mergers and the recoverability of transition costs and of assets that may become impaired.

The Electric Industry — New York State Regulatory Issues
The PSC has instituted a number of cases which will determine the boundaries within which power providers can compete in New York.

In 1994, the PSC completed the first phase of a competitive opportunities proceeding, issuing guidelines that allow New York utilities, at their option, to negotiate discounted rates with customers who otherwise would purchase electricity elsewhere. Any net revenue lost through these negotiations will be shared between ratepayers and shareowners, with percentages to be determined in rate cases. With respect to the Company, the Commission has ruled that the Company's shareowners must bear 30% of any "discount" negotiated by the Company in order to retain customers. While this percentage is comparable to that required of other utilities, the Company believes the percentage should be significantly lower due to the Company's unique financial structure and, therefore, has appealed the PSC's decision.

The PSC has recently begun a second phase of this proceeding in which it will develop principles to guide the transition to a more competitive environment, explore how to improve the wholesale electric market and determine the role regulation will play. The issues to be reviewed include: wholesale competition with or without a spin-off of generation assets; retail competition; planning and reliability; customer impacts; financial and legal considerations; and affordability of electric service to all customers. The PSC will also address the critical issue of whether utilities will be required to write-off assets in order to offer more competitive prices.

In addition, the State Energy Planning Board has released the 1994 State Energy Plan (SEP) which calls for the development of a fully competitive wholesale generation market within five years. While continuing to caution that full retail competition may not be in the best interests of the State, the SEP threatens that retail competition should be considered sooner "in the absence of utility cooperation" in the development of a fully competitive wholesale market.

The Company's Service Territory
The changing utility regulatory environment has affected the Company in a number of ways. For example, PURPA's encouragement of the non-utility generator (NUG) industry has negatively impacted the Company. The Company estimates that in 1994, sales lost to NUGs totaled 237 gigawatt-hours (Gwh) representing a loss in revenues net of fuel (net revenues) of approximately $24 million, or approximately 1.1% of the Company's 1994 net revenues. Additionally, as mentioned above, the Company is required to purchase all the power offered by QFs. As of December 31, 1994, QFs were selling approximately 203 megawatts (MW) of power to the Company.

The Company estimates that, in 1994, purchases from QFs required by federal and State law cost the Company $53 million more than it would have cost had the Company generated this power. The Company has also contracted, beginning in early 1995, to purchase all excess power from the 40 MW Stony Brook project located at the State University of New York at Stony Brook, New York.

QFs have the choice of pricing sales to the Company at either (i) the PSC's published estimates of the Company's long run avoided costs (LRAC) or (ii) the Company's tariff rates, which are modified from time to time, reflecting the Company's actual avoided costs. Additionally, until repealed in 1992, New York State law set a minimum price of six cents per kilowatt-hour (kWh) for utility purchases of power from certain categories of QFs, considerably above the Company's avoided cost. The six cent minimum now only applies to contracts entered into before June 1992. The Company believes that the repeal of the six cent law, coupled with recent PSC updates which resulted in lower LRAC estimates, has significantly reduced the economic benefits to QFs seeking to sell power to the Company.

After the anticipated loss of the Stony Brook load, estimated to be approximately 190 Gwh annually, or a net revenue loss of approximately $13 million, the Company expects that electric load losses due to NUGs will stabilize. The Company believes that a number of factors, including customer load characteristics such as a lack of a significant industrial base and related large thermal load, will mitigate load loss and thereby make cogeneration economically unattractive.

The Company has also experienced a revenue loss as a result of its policy of voluntarily providing wheeling of NYPA power for economic development. The Company estimates that NYPA power has displaced approximately 400 Gwh of annual energy sales. The net revenue loss associated with this amount of sales is approximately $28 million or 1.4% of the Company's 1994 net revenues. Currently, the potential loss of additional load is limited by conditions in the Company's transmission agreements with NYPA.

Aside from NUGs, a number of customer groups are seeking to hasten consideration and implementation of full retail competition. For example, an energy consultant has petitioned the PSC, seeking alternate sources of power for Long Island school districts. The County of Nassau has also petitioned the PSC to authorize retail wheeling for all classes of electric customers in the county. In addition, several towns on Long Island are investigating municipalization. Municipalization, in which customers form a government-sponsored electric supply company, is one form of competition likely to increase as a result of NEPA. The Town of Southampton and several other towns in the Company's service territory are considering the formation of a municipally owned and operated electric authority to replace the services currently provided by the Company. Suffolk County has also approached FERC to determine whether it can qualify as a municipal power authority in order to purchase cheaper electricity from non-Company sources. The Company's geographic location and the limited electrical interconnections to Long Island serve to limit the accessibility of its transmission grid to potential competitors from off the system.

The matters discussed above involve substantial social, economic, legal, environmental and financial issues. The Company is opposed to any proposal that merely shifts costs from one group of ratepayers to another, that fails to enhance the provision of least-cost, efficiently-generated electricity or that fails to provide the Company's shareowners with an adequate return on and recovery of their investment. The Company is unable to predict what action, if any, the PSC or FERC may take regarding any of these matters, or the impact on the Company's financial condition if some or all of these matters are approved or implemented by the appropriate regulatory authority.

Conservation Services

In 1993, the Company filed a modified DSM plan with the PSC to support the objectives of the Company's Electric Rate Plan filed in December 1993. Under this modified plan, the Company proposed a substantially lower level of spending than that initially approved for 1994. The PSC did not approve the Company's proposed plan, but instead issued a ruling in July 1994, which dictated energy savings targets that were greater than those originally proposed by the Company. Specifically, the targets for the Company's DSM programs amounted to a 161.3 MW reduction in coincident peak demand and an annualized energy savings of 702.6 Gwh by December 31, 1994. The Company was successful in its DSM efforts.

In 1995, the Company intends to continue to carefully manage DSM expenditures and more fully transform DSM to a strategic marketing tool which can be used to position the Company for the future. In these efforts, the Company will act to further increase the emphasis on education and information programs and further decrease its emphasis on utility rebate payments. In addition, financing programs and other cost sharing arrangements will be stressed as a means to reduce DSM program costs. Finally, DSM programs will be redesigned to enhance the Company's competitive position through the offering of programs and services to the Company's customers which promote the efficient use of electricity, including energy-efficient load growth.

Results of Operations

Earnings

Summary results of earnings for the years 1994, 1993 and 1992 were as follows:

(In millions of dollars and shares except earnings per share)

	1994	1993	1992
Net income	**$ 301.8**	$ 296.6	$ 302.0
Preferred stock dividend requirements	**53.0**	56.1	64.0
Earnings for common stock	**$ 248.8**	$ 240.5	$ 238.0
Average common shares outstanding	**115.9**	112.1	111.4
Earnings per common share	**$ 2.15**	$ 2.15	$ 2.14

The Company achieved the same level of earnings per common share in 1994 as in 1993 despite an increase in the average number of common shares outstanding. This was primarily the result of the Company's cost containment program and the impact on earnings of positive cash flow from operations, which allowed the Company to use cash balances to satisfy maturing debt.

The electric business achieved a higher level of earnings in 1994 as compared to 1993, offset by a decrease in the gas business earnings. The decrease in gas business earnings in 1994 was the result of several factors including: (i) a lower allowed return on common equity; (ii) a write-off in 1994, of previously deferred storm costs and (iii) a provision in the Company's gas rate structure which became effective December 1, 1993, which requires earnings in excess of a 10.6% return on common equity be shared equally between the Company's firm gas customers and its shareowners.

The earnings in the electric business were lower in 1993 when compared to 1992 due primarily to the expensing of previously deferred storm costs, lower interest rates associated with short-term investments and certain regulatory adjustments recorded in accordance with the Company's electric rate structure. The lower level of earnings in the electric business was offset by a significant increase in earnings in the gas business, resulting from the continuation of the Company's gas expansion program.

Revenues

Total revenues, including revenues from recovery of fuel costs, were $3.1 billion, $2.9 billion and $2.6 billion for the years 1994, 1993 and 1992, respectively.

Electric Revenues

Revenues from the Company's electric operations for the years 1994, 1993 and 1992 were $2.5 billion, $2.4 billion and $2.2 billion, respectively.

In November 1991, the PSC approved the LRPP, which provided the Company with annual electric rate increases of 4.15%, 4.1% and 4.0% for the rate years beginning December 1, 1991, 1992 and 1993, respectively. These rate increases provided $69 million of additional revenues in 1994 as compared to 1993, and $75 million of additional revenues in 1993 as compared to 1992.

The LRPP contains several regulatory mechanisms that impact the level of revenues, but have no impact on earnings. The Company's current electric rate structure provides for a revenue reconciliation, which eliminates the impact on earnings of experiencing sales that are above or below the levels reflected in rates. As a result of lower than adjudicated electric sales, the Company recorded non-cash income, which is included in "Other Regulatory Amortization," of $50.9 million, $43.5 million and $78.5 million in 1994, 1993 and 1992, respectively.

Under the LRPP, base fuel costs collected in rates in excess of actual fuel costs are applied as a reduction to the RMC. The Company applied $83.9 million, $37.5 million and $22.9 million of amounts collected in excess of actual fuel costs as a reduction to the RMC for the rate years ended November 30, 1994, 1993 and 1992, respectively.

Under the LRPP, deferred balances associated with the reconciliation of revenue, expenses and performance incentives in excess of $15 million per annum are returned to or recovered from the ratepayers through the FCA. During the period August 1993 through July 1994, the Company collected, through the FCA, approximately $2.7 million per month for an aggregate of $30.2 million related to the deferred balances for the rate year ended November 30, 1992. Since August 1994, the PSC has allowed the Company to continue the collection of a like amount through the FCA which will continue through the end of the suspension period. These additional revenues, amounting to approximately $13.4 million through December 1994, were recorded as a reduction to the RMC. The Company is awaiting PSC approval for the recovery of $48.1 million and $63.6 million for the 1993 and 1994 rate year deferrals. For a further discussion of the LRPP regulatory mechanisms, see Note 3 of Notes to Financial Statements.

Total electric sales volumes in millions of kWh were 16,382 in 1994, 16,128 in 1993 and 15,667 in 1992. The increase in sales in 1994 and 1993 was primarily the result of warmer than normal weather experienced in the summer months. The increases in sales were partially offset by sales lost to non-utility generators and power displaced by NYPA, discussed above under the heading "Competitive Environment." In 1994 and 1993, the composition of system sales was 45% residential and 52% commercial/industrial. In 1992, the composition was 44% residential and 53% commercial/industrial.

Gas Revenues
Revenues from the Company's gas operations for the years 1994, 1993 and 1992 were $586 million, $529 million and $427 million, respectively.

In December 1993, the PSC approved a three year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provides the Company with annual gas rate increases of 4.7%, 3.8% and 2.8% for the rate years beginning December 1, 1993, 1994 and 1995, respectively. The Company had also received an annual gas rate increase of 7.1% effective December 1, 1992. These rate increases provided $25 million in additional revenues for 1994 as compared to 1993, and $35 million in additional revenues for 1993 as compared to 1992.

Total firm sales volumes in thousands of dekatherms (Mdth) were 58,889 in 1994, 59,183 in 1993 and 56,292 in 1992. In 1994, firm sales volumes decreased when compared to 1993 primarily due to warmer weather experienced during the 1994 heating season as compared to 1993, partially offset by the addition of approximately 8,500 new gas space heating customers resulting from the continuation of the Company's gas expansion program. The number of monthly average space heating customers was 273,633, 266,665 and 259,500 for the years 1994, 1993 and 1992, respectively. The Company has a weather normalization clause which mitigates the impact on revenues of experiencing weather that is warmer or colder than the "normal" value used for projecting sales. In 1993, firm sales volumes increased as a result of colder weather experienced during the 1993 heating season as compared to 1992 combined with additional gas space heating customers resulting from the Company's gas expansion program.

The Company began selling gas off-system in 1993. Off-system gas sales revenues were $26 million and $8 million on volumes of 7,232 Mdth and 2,894 Mdth, for the years ended December 31, 1994 and 1993, respectively. Any profits realized from off-system sales are allocated 85% to ratepayers and 15% to shareowners.

Recoveries of gas fuel expenses increased revenues by $33 million and $26 million in 1994 and 1993, respectively. In 1994, the increase in the recoveries of gas fuel expenses was primarily due to increased billed sales volumes and higher average gas prices, when compared to 1993. In 1993, the increase was primarily due to higher average gas prices, when compared to 1992.

Operating Expenses
Fuel and Purchased Power
Summary of fuel and purchased power expenses for the years 1994, 1993 and 1992 were as follows:

(In thousands of dollars)

	1994	*1993*	*1992*
Fuel for Electric Operations			
Oil	**$ 145**	$ 180	$ 190
Gas	**101**	93	79
Nuclear	**15**	13	11
Purchased power	**308**	293	280
Total	**569**	579	560
Gas fuel	**279**	249	182
Total	**$ 848**	$ 828	$ 742

Despite an increase in electric sales volumes during 1994 and rising fuel oil prices, fuel for electric operations decreased primarily as a result of the Company's efforts to reduce its dependency on oil as the primary fuel for electric generation. The Company, over the past several years, has refitted several generating facilities to enable them to burn either oil or natural gas, depending upon the relative cost of each commodity at any given time.

In addition to the increased use of natural gas, the Company has reduced oil consumption by using energy generated at Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) and by purchasing power from other systems, cogenerators and independent power producers. The total barrels of oil consumed for electric operations was 7.5 million, 9.7 million and 10.7 million, for the years 1994, 1993 and 1992, respectively.

Cogenerators and independent power producers provided approximately 9% of the Company's system requirements in 1994, 1993 and 1992. The increase in purchased power expenses in 1994 is primarily attributable to purchases from the 136 MW facility in Holtsville, New York, owned by NYPA, constructed for the benefit of the Company.

Summary of electric fuel and purchased power mix for the years 1994, 1993 and 1992 were as follows:

	(Percent of system energy requirements)		
	1994	*1993*	*1992*
Oil	**25%**	33%	37%
Gas	**23**	19	19
Nuclear	**9**	7	6
Purchased power	**43**	41	38
Total	**100%**	100%	100%

Gas fuel expenses for gas operations increased by $30 million and $67 million in 1994 and 1993, respectively. The increase in 1994 is primarily attributable to the additional fuel costs associated with the Company's off-system gas sales, while the increase for 1993 was primarily due to significantly higher gas prices and increased volumes, as a result of colder than normal weather during the heating season.

Operations and Maintenance Expenses
Operations and maintenance (O&M) expenses, excluding fuel and purchased power, were $541 million, $522 million and $498 million, for the years 1994, 1993 and 1992, respectively. The increase in O&M for 1994 was primarily due to the recognition of previously deferred storm costs associated with gas operations, an increase in costs associated with the Company's gas expansion program, the recognition of certain costs which exceeded the Company's insurance recoveries, an increase in employee benefit costs and the effects of inflation. These higher O&M expenses were partially offset by the continuation of the Company's cost containment program. The increase in 1993 was principally due to the recognition of previously deferred storm costs associated with electric operations, the recording of higher accruals for uncollectible accounts and higher transmission and distribution costs for both the electric and gas businesses.

Rate Moderation Component and Related Carrying Charges
In 1994 and 1993, the Company recorded non-cash charges to income [illegible] approximately $198 million and $89 million, respectively, representing the amortization of the RMC. In 1992, the Company recorded non-cash income of approximately $30 million, representing the accretion of the RMC. The Company accrues a carrying charge on the unamortized balance of the RMC which amounted to $32 million, $40 million and $43 million for the years 1994, 1993 and 1992, respectively. For further discussion on the RMC, see Notes 1, 2 and 3 of Notes to Financial Statements.

Other Regulatory Amortization
In 1994, other regulatory amortization was a non-cash charge to incor[illegible] 4.3 million, compared to a non-cash credit to income of $18.[illegible] ion in 1993. The change reflects an increase in the amortization of LRPP deferrals, higher amortization of Shoreham post settlement costs and a non-cash charge to income reflecting the operation of the interest deferral mechanism, as defined in the Company's electric rate structure. These items were partially offset by higher deferred net margin revenues, discussed above under "Revenues."

In 1993, other regulatory amortization was lower than 1992 as a result of lower net margin revenues and the amortization of the 1992 rate year LRPP deferrals which began in August 1993. Partially offsetting these items was the recognition of additional non-cash credits to income resulting from the operation of the interest deferral mechanism. For a discussion on the Company's rate mechanisms, see Note 3 of Notes to Financial Statements.

Operating Taxes
Operating taxes were $407 million, $386 million and $389 million, for the years 1994, 1993 and 1992, respectively. The increase in operating taxes of approximately $21 million in 1994 when compared to 1993 is primarily attributable to higher gross receipts taxes, resulting from increased revenues, higher property taxes, additional payroll taxes and higher dividend taxes.

Interest Expense

The reduction in interest expense in 1994 when compared to 1993 is primarily attributable to lower outstanding debt levels. The Company's strategy is to apply available cash balances toward the satisfaction of debt whenever practicable. During 1994, the Company used approximately $200 million of cash on hand and the proceeds from the issuance of 5.1 million shares of common stock to help lower debt by approximately $300 million. The lower interest expense also reflects the satisfaction of $175 million of maturing debt in November 1993, with cash on hand.

The increase in 1993 when compared to 1992 was attributable to higher debt levels and the conversion in June 1992 of $400 million of tax-exempt securities from a weekly variable interest rate to a higher thirty year fixed rate. Also contributing to the increase was the issuance in November 1992 of thirty year fixed rate debentures, the proceeds of which were used to eliminate variable rate bank debt. The conversion of the tax-exempt securities and refinancing of bank debt was done in order to take advantage of historically low long-term interest rates. Partially offsetting this increase in interest expense were savings realized from the effects of the Company's aggressive refinancing of higher-cost debt in 1993.

Accounting Pronouncements

Effective January 1, 1993, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. Under a PSC order issued in response to SFAS No. 106, the Company defers as a regulatory asset the difference between postretirement benefits expense recorded for accounting purposes in accordance with SFAS No. 106 and postretirement expenses reflected in rates. The PSC order also requires that the ongoing annual postretirement benefit expense be phased into and fully recovered in rates within a five year period, with the accumulated postretirement benefit obligation being recovered in rates over a twenty year period. The adoption of SFAS No. 106 had no impact on net income for the years ended December 31, 1994 and 1993. For a further discussion of SFAS No. 106, see Notes 1 and 8 of Notes to Financial Statements.

Effective January 1, 1993, the Company adopted SFAS No. 109, Accounting for Income Taxes. SFAS No. 109 requires utilities to establish deferred tax assets and liabilities for, among other things, transactions that were not recognized under Accounting Principles Board Opinion No. 11, Accounting for Income Taxes. SFAS No. 109 provides that regulatory assets and liabilities may be established for these specific SFAS No. 109 created deferred tax assets and liabilities providing that the regulator provides for the future recovery or return of these amounts through rates. As a result of a PSC order issued in January 1993, providing for the recovery or return of such amounts, the Company has recorded regulatory tax assets and liabilities to offset the effect of accumulated deferred tax liabilities and assets created as a result of adopting SFAS No. 109. The adoption of SFAS No. 109 had no impact on net income for the years ended December 31, 1994 and 1993. For a further discussion of SFAS No. 109, see Notes 1 and 9 of Notes to Financial Statements.

Selected Financial Data

Additional information respecting revenues, expenses, electric and gas operating income and operations data and balance sheet information for the last five years is provided in Tables 1 through 11 of Selected Financial Data. Information with regard to the Company's business segments for the last three years is provided in Note 11 of Notes to Financial Statements.

Balance Sheet

Assets	(In thousands of dollars)	
At December 31	***1994***	*1993*
Utility Plant		
Electric	**$ 3,657,178**	$ 3,544,569
Gas	**994,742**	860,899
Common	**232,346**	201,418
Construction work in progress	**129,824**	176,504
Nuclear fuel in process and in reactor	**23,251**	16,533
	5,037,341	4,799,923
Less — Accumulated depreciation and amortization	**1,538,995**	1,452,366
Total Net Utility Plant	**3,498,346**	3,347,557
Regulatory Assets		
Base financial component (less accumulated amortization of $555,340 and $454,369)	**3,483,490**	3,584,461
Rate moderation component	**463,229**	609,827
Shoreham post settlement costs	**922,580**	777,103
Shoreham nuclear fuel	**73,371**	75,497
Postretirement benefits other than pensions	**412,727**	402,921
Regulatory tax asset	**1,831,689**	1,848,998
Other	**354,524**	311,832
Total Regulatory Assets	**7,541,610**	7,610,639
Nonutility Property and Other Investments	**24,043**	23,029
Current Assets		
Cash and cash equivalents	**185,451**	248,532
Special deposits	**27,614**	23,439
Customer accounts receivable (less allowance for doubtful accounts of $23,365 and $23,889)	**245,125**	249,074
Other accounts receivable	**14,030**	12,199
Accrued unbilled revenues	**164,379**	170,042
Materials and supplies at average cost	**74,777**	68,882
Fuel oil at average cost	**37,723**	35,857
Gas in storage at average cost	**68,447**	75,182
Prepayments and other current assets	**33,878**	41,652
Total Current Assets	**851,424**	924,859
Deferred Charges		
Deferred federal income tax	**951,766**	1,094,088
Unamortized cost of issuing securities	**313,207**	350,239
Other	**36,284**	42,705
Total Deferred Charges	**1,301,257**	1,487,032
Total Assets	**$ 13,216,680**	$ 13,393,116

See Notes to Financial Statements

Capitalization and Liabilities

At December 31 (In thousands of dollars)	1994	1993
Capitalization		
Long-term debt	**$ 5,162,675**	$ 4,887,733
Unamortized discount on debt	**(17,278)**	(17,393)
	5,145,397	4,870,340
Preferred stock — redemption required	**644,350**	649,150
Preferred stock — no redemption required	**63,957**	64,038
Total Preferred Stock	**708,307**	713,188
Common stock	**592,083**	561,662
Premium on capital stock	**1,101,240**	1,010,283
Capital stock expense	**(52,175)**	(50,427)
Retained earnings	**752,480**	711,432
Total Common Shareowners' Equity	**2,393,628**	2,232,950
Total Capitalization	**8,247,332**	7,816,478
Regulatory Liabilities		
Regulatory liability component	**357,117**	436,476
1989 Settlement credits	**145,868**	155,081
Regulatory tax liability	**111,218**	114,748
Other	**143,611**	138,612
Total Regulatory Liabilities	**757,814**	844,917
Current Liabilities		
Current maturities of long-term debt	**25,000**	600,000
Current redemption requirements of preferred stock	**4,800**	4,800
Accounts payable and accrued expenses	**241,775**	277,519
Accrued taxes (including federal income tax of $28,340 and $28,424)	**58,133**	52,656
Accrued interest	**149,929**	142,409
Dividends payable	**57,367**	54,542
Class Settlement	**40,000**	30,000
Customer deposits	**28,474**	27,046
Total Current Liabilities	**605,478**	1,188,972
Deferred Credits		
Deferred federal income tax	**2,941,793**	2,932,029
Class Settlement	**147,437**	164,942
Other	**13,204**	12,622
Total Deferred Credits	**3,102,434**	3,109,593
Operating Reserves		
Pensions and other postretirements benefits	**453,016**	424,442
Claims and damages	**50,606**	8,714
Total Operating Reserves	**503,622**	433,156
Commitments and Contingencies	**—**	—
Total Capitalization and Liabilities	**$ 13,216,680**	$ 13,393,116

See Notes to Financial Statements

Statement of Income

For year ended December 31	*1994*	*1993*	*1992*
	(In thousands of dollars except per share amounts)		
Revenues			
Electric	**$ 2,481,637**	$ 2,352,109	$ 2,194,632
Gas	**585,670**	528,886	427,207
Total Revenues	**3,067,307**	2,880,995	2,621,839
Operating Expenses			
Operations — fuel and purchased power	**847,986**	827,591	741,784
Operations — other	**406,014**	387,808	372,209
Maintenance	**134,640**	133,852	125,736
Depreciation and amortization	**130,664**	122,471	119,137
Base financial component amortization	**100,971**	100,971	100,971
Rate moderation component amortization	**197,656**	88,667	(30,444)
Regulatory liability component amortization	**(79,359)**	(79,359)	(79,359)
1989 Settlement credits amortization	**(9,214)**	(9,214)	(9,214)
Other regulatory amortization	**4,328**	(18,044)	(22,072)
Operating taxes	**406,895**	385,847	388,988
Federal income tax — current	**10,784**	6,324	530
Federal income tax — deferred and other	**170,997**	178,530	172,468
Total Operating Expenses	**2,322,362**	2,125,444	1,880,734
Operating Income	**744,945**	755,551	741,105
Other Income and (Deductions)			
Allowance for other funds used during construction	**2,716**	2,473	4,725
Rate moderation component carrying charges	**32,321**	40,004	42,837
Other income and deductions, net	**35,343**	38,997	29,273
Class Settlement	**(22,730)**	(23,178)	(22,541)
Federal income tax — deferred and other	**5,069**	12,578	12,036
Total Other Income and (Deductions)	**52,719**	70,874	66,330
Income Before Interest Charges	**797,664**	826,425	807,435
Interest Charges and (Credits)			
Interest on long-term debt	**437,751**	466,538	450,621
Other interest	**62,345**	67,534	62,226
Allowance for borrowed funds used during construction	**(4,284)**	(4,210)	(7,386)
Total Interest Charges and (Credits)	**495,812**	529,862	505,461
Net Income	**301,852**	296,563	301,974
Preferred stock dividend requirements	**53,020**	56,108	63,954
Earnings for Common Stock	**$ 248,832**	$ 240,455	$ 238,020
Average Common Shares Outstanding (000)	**115,880**	112,057	111,439
Earnings per Common Share	**$ 2.15**	$ 2.15	$ 2.14
Dividends Declared per Common Share	**$ 1.78**	$ 1.76	$ 1.72

See Notes to Financial Statements

Statement of Cash Flows

			(In thousands of dollars)
For year ended December 31	**1994**	1993	1992
Operating Activities			
Net Income	**$ 301,852**	$ 296,563	$ 301,974
Adjustments to reconcile net income to net cash provided by operating activities			
Provision for doubtful accounts	**19,542**	18,555	16,329
Depreciation and amortization	**130,664**	122,471	119,137
Base financial component amortization	**100,971**	100,971	100,971
Rate moderation component amortization	**197,656**	88,667	(30,444)
Regulatory liability component amortization	**(79,359)**	(79,359)	(79,359)
1989 Settlement credits amortization	**(9,214)**	(9,214)	(9,214)
Other regulatory amortization	**4,328**	(18,044)	(22,072)
Rate moderation component carrying charges	**(32,321)**	(40,004)	(42,837)
Class Settlement	**22,730**	23,178	22,541
Amortization of cost of issuing and redeeming securities	**46,237**	52,063	41,204
Federal income tax — deferred and other	**165,928**	165,952	160,432
Allowance for other funds used during construction	**(2,716)**	(2,473)	(4,725)
Gas cost adjustment	**11,709**	(3,499)	(24,142)
Other	**37,538**	15,200	1,035
Changes in operating assets and liabilities			
Accounts receivable	**(17,353)**	(65,898)	(14,275)
Class Settlement	**(30,235)**	(25,302)	(19,039)
Accrued unbilled revenues	**5,663**	(26,870)	(6,607)
Materials and supplies, fuel oil and gas in storage	**(1,026)**	5,265	(10,933)
Prepayments and other current assets	**7,774**	(1,250)	(5,548)
Accounts payable and accrued expenses	**(44,598)**	(8,800)	62,513
Accrued taxes	**5,477**	(14,869)	7,351
Other	**(5,458)**	(11,290)	25,772
Net Cash Provided by Operating Activities	**835,749**	582,013	590,064
Investing Activities			
Construction and nuclear fuel expenditures	**(276,954)**	(302,220)	(268,179)
Shoreham post settlement costs	**(167,367)**	(207,114)	(227,658)
Other	**(1,349)**	(934)	(1,484)
Net Cash Used in Investing Activities	**(445,670)**	(510,268)	(497,321)
Financing Activities			
Proceeds from issuance of long-term debt	**331,326**	1,089,770	1,659,928
Proceeds from sale of common stock	**118,108**	14,323	5,670
Proceeds from sale of preferred stock	**—**	201,709	411,373
Redemption of long-term debt	**(635,058)**	(960,000)	(1,344,283)
Redemption of preferred stock	**(4,800)**	(205,600)	(389,428)
Common stock dividends paid	**(205,086)**	(195,794)	(190,477)
Preferred stock dividends paid	**(52,927)**	(56,727)	(69,923)
Cost of issuing and redeeming securities	**(5,871)**	(17,036)	(166,066)
Other	**1,148**	(3,343)	1,850
Net Cash Used in Financing Activities	**(453,160)**	(132,698)	(81,356)
Net (Decrease) Increase in Cash and Cash Equivalents	**$ (63,081)**	$ (60,953)	$ 11,387
Cash and cash equivalents at January 1	**$ 248,532**	$ 309,485	$ 298,098
Net (decrease) increase in cash and cash equivalents	**(63,081)**	(60,953)	11,387
Cash and Cash Equivalents at December 31	**$ 185,451**	$ 248,532	$ 309,485
Interest paid, before reduction for the allowance for borrowed funds used during construction	**$ 446,340**	$ 469,978	$ 424,842
Federal income tax — paid	**$ 10,780**	$ 6,000	$ 2,100
Federal income tax — refunded	**$ —**	$ 1,000	$ 1,566

See Notes to Financial Statements

Statement of Retained Earnings

	(In thousands of dollars)		
	1994	1993	1992
Balance at January 1	**$ 711,432**	$ 667,988	$ 620,373
Net income for the year	**301,852**	296,563	301,974
	1,013,284	964,551	922,347
Deductions			
Cash dividends declared on common stock	**207,794**	197,236	191,693
Cash dividends declared on preferred stock	**53,046**	55,861	62,387
Other adjustments	**(36)**	22	279
Balance at December 31	**$ 752,480**	$ 711,432	$ 667,988

See Notes to Financial Statements

Statement of Capitalization

	Shares Outstanding		(In thousands of dollars)	
At December 31	**1994**	1993	**1994**	1993
Common Shareowners' Equity				
Common stock, $5.00 par value	**118,416,606**	112,332,490	**$ 592,083**	$ 561,662
Premium on capital stock			**1,101,240**	1,010,283
Capital stock expense			**(52,175)**	(50,427)
Retained earnings			**752,480**	711,432
Total Common Shareowners' Equity			**2,393,628**	2,232,950
Preferred Stock — Redemption Required				
Par value $100 per share				
7.40% Series L	**182,000**	192,500	**18,200**	19,250
8.50% Series R	**75,000**	112,500	**7,500**	11,250
7.66% Series CC	**570,000**	570,000	**57,000**	57,000
Less — Sinking fund requirement			**4,800**	4,800
			77,900	82,700
Par value $25 per share				
7.95% Series AA	**14,520,000**	14,520,000	**363,000**	363,000
$1.67 Series GG	**880,000**	880,000	**22,000**	22,000
$1.95 Series NN	**1,554,000**	1,554,000	**38,850**	38,850
7.05% Series QQ	**3,464,000**	3,464,000	**86,600**	86,600
6.875% Series UU	**2,240,000**	2,240,000	**56,000**	56,000
			566,450	566,450
Total Preferred Stock — Redemption Required			**644,350**	649,150
Preferred Stock — No Redemption Required				
Par value $100 per share				
5.00% Series B	**100,000**	100,000	**10,000**	10,000
4.25% Series D	**70,000**	70,000	**7,000**	7,000
4.35% Series E	**200,000**	200,000	**20,000**	20,000
4.35% Series F	**50,000**	50,000	**5,000**	5,000
5⅛% Series H	**200,000**	200,000	**20,000**	20,000
5¾% Series I - Convertible	**19,569**	20,375	**1,957**	2,038
Total Preferred Stock — No Redemption Required			**63,957**	64,038
Total Preferred Stock			**$ 708,307**	$ 713,188

See Notes to Financial Statements

Statement of Capitalization (continued)

(in thousands of dollars)

At December 31	Maturity	Interest Rate	Series	1994	1993
First Mortgage Bonds (excludes Pledged Bonds)	June 1, 1994	4⅝%	N	**$ —**	$ 25,000
	June 1, 1995	4.55%	O	**25,000**	25,000
	March 1, 1996	5¼%	P	**40,000**	40,000
	April 1, 1997	5½%	Q	**35,000**	35,000
Total First Mortgage Bonds				**100,000**	125,000
General and Refunding Bonds	May 1, 1996	8¾%		**415,000**	415,000
	February 15, 1997	8¾%		**250,000**	250,000
	April 15, 1998	7⅝%		**100,000**	—
	May 15, 1999	7.85%		**56,000**	56,000
	April 15, 2004	8⅝%		**185,000**	—
	May 15, 2006	8.50%		**75,000**	75,000
	July 15, 2008	7.90%		**80,000**	80,000
	May 1, 2021	9¾%		**415,000**	415,000
	July 1, 2024	9⅝%		**375,000**	375,000
Total General and Refunding Bonds				**1,951,000**	1,666,000
Debentures	June 15, 1994	10.25%		**—**	400,000
	November 15, 1994	11.75%		**—**	175,000
	June 15, 1999	10.875%		**—**	30,545
	July 15, 1999	7.30%		**397,000**	397,000
	January 15, 2000	7.30%		**36,000**	36,000
	July 15, 2001	6.25%		**145,000**	145,000
	March 15, 2003	7.05%		**150,000**	150,000
	March 1, 2004	7.00%		**59,000**	59,000
	June 1, 2005	7.125%		**200,000**	200,000
	March 1, 2007	7.50%		**142,000**	142,000
	June 15, 2019	11.375%		**—**	4,513
	July 15, 2019	8.90%		**420,000**	420,000
	November 1, 2022	9.00%		**451,000**	451,000
	March 15, 2023	8.20%		**270,000**	270,000
Total Debentures				**2,270,000**	2,880,058
Authority Financing Notes					
Industrial Development Revenue Bonds	December 1, 2006	7.5%	1976 A,B	**2,000**	2,000
Pollution Control Revenue Bonds	December 1, 2006	7.5%	1976 A	**28,375**	28,375
	December 1, 2009	7.8%	1979 B	**19,100**	19,100
	October 1, 2012	8¼%	1982	**17,200**	17,200
	March 1, 2016	3.0%	1985 A,B	**150,000**	150,000
Electric Facilities Revenue Bonds	September 1, 2019	7.15%	1989 A,B	**100,000**	100,000
	June 1, 2020	7.15%	1990 A	**100,000**	100,000
	December 1, 2020	7.15%	1991 A	**100,000**	100,000
	February 1, 2022	7.15%	1992 A,B	**100,000**	100,000
	August 1, 2022	6.9%	1992 C,D	**100,000**	100,000
	November 1, 2023	5.45%	1993 A	**50,000**	50,000
	November 1, 2023	4.90%	1993 B	**50,000**	50,000
	October 1, 2024	5.40%	1994 A	**50,000**	—
Total Authority Financing Notes				**866,675**	816,675
Unamortized discount on debt				**(17,278)**	(17,393)
Total				**5,170,397**	5,470,340
Less current maturities				**25,000**	600,000
Total Long-Term Debt				**5,145,397**	4,870,340
Total Capitalization				**$8,247,332**	$7,816,478

See Notes to Financial Statements

Note 1. Summary of Significant Accounting Policies

Regulation

The Company's accounting policies conform to generally accepted accounting principles as they apply to a regulated enterprise. Its accounting records are maintained in accordance with the Uniform Systems of Accounts prescribed by the Public Service Commission of the State of New York (PSC) and the Federal Energy Regulatory Commission (FERC).

Regulatory Assets and Liabilities

General

The Company's Balance Sheet reflects the rate actions of its regulators through the creation of regulatory assets and liabilities. Regulatory assets are generally created whenever it is probable that the regulators will permit the recovery through rates of a previously incurred cost that would otherwise be charged to expense. Regulatory liabilities are generally created whenever it is probable that the regulators will require a return through rates of revenues or gains that would otherwise be recorded to income.

Base Financial Component and Rate Moderation Component

Pursuant to the 1989 Settlement, the Company recorded a regulatory asset known as the Financial Resource Asset (FRA). The FRA is designed to provide the Company with sufficient cash flows to assure its financial recovery. The FRA has two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC).

The BFC represents the present value of the future net-after-tax cash flows which the Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provided the Company for its financial recovery. The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis which began July 1, 1989.

The RMC reflects the difference between the Company's revenue requirements under conventional ratemaking and the revenues resulting from the implementation of the rate moderation plan provided for in the RMA. For a further discussion of the 1989 Settlement and FRA, see Note 2.

Shoreham Post Settlement Costs

The balance consists of Shoreham Nuclear Power Station (Shoreham) decommissioning costs, fuel disposal costs, payments in lieu of taxes, carrying charges and other costs. These costs are being capitalized and amortized, and recovered through rates over a forty year period on a straight-line remaining life basis which began July 1, 1989.

Shoreham Nuclear Fuel

The balance principally reflects the unamortized portion of Shoreham nuclear fuel which was reclassified from Nuclear Fuel in Process and in Reactor at the time of the 1989 Settlement. This amount is being amortized and recovered through rates over a forty year period on a straight-line remaining life basis which began July 1, 1989.

Postretirement Benefits Other Than Pensions

Under a PSC order issued in response to the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, the Company defers as a regulatory asset the difference between postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and postretirement benefit expense reflected in rates. Pursuant to the PSC order, the ongoing annual postretirement benefit expense must be phased into and fully recovered in rates within a five year period, with the accumulated postretirement obligation being recovered in rates over a twenty year period. For a further discussion of SFAS No. 106, see Note 8.

Regulatory Tax Asset/Liability

SFAS No. 109, Accounting for Income Taxes, requires utilities to establish deferred tax assets and liabilities for, among other things, transactions that did not give rise to deferred tax assets and liabilities under Accounting Principles Board (APB) Opinion No. 11, Accounting for Income Taxes. SFAS No. 109 provides that regulatory assets and liabilities may be established for these specific SFAS No. 109 created deferred tax assets and liabilities providing that the regulator provides for the future recovery or return of these amounts through rates. As a result of a PSC order issued in January 1993, providing for the recovery or return of such amounts, the Company has recorded regulatory tax assets and liabilities to offset the effect of accumulated deferred tax liabilities and assets created as a result of adopting SFAS No. 109.

The tax effects of other differences between income for financial statement purposes and for federal income tax purposes are accounted for as current adjustments in federal income tax provisions.

Regulatory Liability Component

Pursuant to the 1989 Settlement, certain tax benefits attributable to the Shoreham abandonment are to be shared between ratepayers and shareowners. A regulatory liability of approximately \$794 million was recorded in June 1989 to preserve an amount equivalent to the ratepayer tax benefits attributable to the Shoreham abandonment. This amount is being amortized over a ten year period on a straight-line basis which began July 1, 1989.

1989 Settlement Credits

The balance represents the unamortized portion of an adjustment of the book write-off to the negotiated 1989 Settlement amount. A portion of this amount is being amortized over a ten year period which began on July 1, 1989. The remaining portion is not currently being recognized for ratemaking purposes.

Utility Plant

Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, indirect costs associated with an addition or replacement and an allowance for the cost of funds used during construction. The cost of renewals and betterments relating to units of property is added to utility plant. The cost of property replaced, retired or otherwise disposed of is deducted from utility plant and, generally, together with dismantling costs less any salvage, is charged to accumulated depreciation. The cost of repairs and minor renewals is charged to maintenance expense. Mass properties (such as poles, wire and meters) are accounted for on an average unit cost basis by year of installation.

Allowance for Funds Used During Construction

The Uniform Systems of Accounts defines the allowance for funds used during construction (AFC) as the net cost of borrowed funds for construction purposes and a reasonable rate of return upon the utility's equity when so used. AFC is not an item of current cash income. AFC is computed monthly using a rate permitted by FERC on a portion of construction work in progress. The average annual AFC rate, without giving effect to compounding, was 9.18%, 9.73% and 9.98% for the years 1994, 1993 and 1992, respectively.

Depreciation

The provisions for depreciation result from the application of straight-line rates to the original cost, by groups, of depreciable properties in service. The rates are determined by age-life studies performed annually on depreciable properties. Depreciation for electric properties was equivalent to approximately 3.0%, 3.0% and 3.2% of respective average depreciable plant costs for the years 1994, 1993 and 1992. Depreciation for gas properties was equivalent to approximately 2.0%, 2.0% and 2.6% of respective average depreciable plant costs for the years 1994, 1993 and 1992.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with maturities of three months or less when purchased. The carrying amount approximates fair value because of the short maturity of these investments.

Fair Values of Financial Instruments

The fair values for the Company's long-term debt and redeemable preferred stock are based on quoted market prices, where available. The fair values for all other long-term debt and redeemable preferred stock are estimated using discounted cash flow analyses which are based upon the Company's current incremental borrowing rate for similar types of securities.

Capitalization — Premiums, Discounts and Expenses

Premiums or discounts and expenses related to the issuance of long-term debt are amortized over the life of each issue. Unamortized premiums or discounts and expenses related to issues of long-term debt that are refinanced are amortized and recovered through rates over the shorter life of either the redeemed issue or the new issue. Capital stock expense and redemption costs related to certain issues of preferred stock that have been refinanced as well as the cost of issuance of the preferred stock issued are recorded as deferred charges. These amounts are being amortized and recovered through rates over the shorter life of the redeemed issue or the new issue.

Revenues

The Company accrues electric and gas revenues for services rendered to customers but not billed at month-end. The Company's electric rate structure, discussed in Note 3, provides for a revenue reconciliation mechanism which eliminates the impact on earnings of experiencing electric sales that are above or below the levels reflected in rates. The Company's gas structure provides for a weather normalization clause, which reduces the impact on revenues of experiencing weather which is warmer or colder than the "normal" value used for projecting sales.

Fuel Cost Adjustments

The Company's electric and gas tariffs include fuel cost adjustment (FCA) clauses which provide for the disposition of the difference between actual fuel costs and the fuel costs allowed in the Company's base tariff rates (base fuel costs). The Company defers these differences to future periods in which they will be billed or credited to customers, except for base electric fuel costs in excess of actual electric fuel costs, which are currently credited to the RMC as incurred.

Federal Income Tax

Effective January 1, 1993, the Company adopted SFAS No. 109. As permitted under SFAS No. 109, the Company elected not to restate the financial statements of prior years.

The Company provides deferred federal income taxes with respect to certain items of income and expense that are reported in different years for financial statement purposes and for federal income tax purposes.

The Company defers the benefit of 60% of pre-1982 gas and pre-1983 electric and 100% of all other investment tax credits, with respect to regulated properties, when realized on its tax returns. Accumulated deferred investment tax credits are amortized ratably over the lives of the related properties.

For ratemaking purposes, the Company provides deferred federal income taxes with respect to certain differences between income before income taxes and taxable income in certain instances when approved by the PSC, as disclosed in Note 9. Also certain accumulated deferred federal income taxes are deducted from rate base and amortized or otherwise applied as a reduction (increase) in federal income tax expense in future years.

Reserves for Claims and Damages
Losses arising from claims against the Company, including workers' compensation claims, property damage, extraordinary storm costs and general liability claims, are partially self-insured. Reserves for these claims and damages are based on, among other things, experience, risk of loss and the ratemaking practices of the PSC. Extraordinary storm losses incurred by the Company are partially insured by certain commercial insurance carriers. These insurance carriers provide partial insurance coverage for individual storm losses to the Company's transmission and distribution system between $5 million and $50 million. Storm losses which are outside of the above-mentioned range are self-insured by the Company. The Company is currently assessing its storm insurance requirements, as current policies expire March 1, 1995.

Reclassifications
Certain prior year amounts have been reclassified in the financial statements to be consistent with the current year's presentation.

Note 2. The 1989 Settlement

On February 28, 1989, the Company and the State of New York entered into the 1989 Settlement resolving certain issues relating to the Company and providing, among other matters, for the financial recovery of the Company and for the transfer of Shoreham and its subsequent decommissioning. Upon the effectiveness of the 1989 Settlement, in June 1989, the Company simultaneously recorded on its Balance Sheet the retirement of its investment of approximately $4.2 billion principally in Shoreham and the establishment of the FRA.

The BFC, a component of the FRA, as initially established, represents the present value of the future net-after-tax cash flows which the RMA provided the Company for its financial recovery.

The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis that began July 1, 1989. At December 31, 1994 and 1993, the unamortized balance of the BFC was approximately $3.5 billion and $3.6 billion, respectively.

The RMC, a component of the FRA, reflects the difference between the Company's revenue requirements under conventional ratemaking and the revenues resulting from the implementation of the rate moderation plan provided for in the RMA. Prior to December 31, 1992, the RMC had increased as the difference between revenues resulting from the implementation of the rate moderation plan provided for in the RMA and revenue requirements under conventional ratemaking, together with a carrying charge equal to the allowed rate of return on rate base, was deferred. The RMC had provided the Company with a substantial amount of non-cash earnings from the effective date of the 1989 Settlement through December 31, 1992. Subsequent to December 31, 1992, the RMC balance had been decreasing as revenues resulting from the operation of the rate moderation plan exceeded revenue requirements under conventional ratemaking. The RMC is currently adjusted, on a monthly basis, for the Company's share of certain Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) operations and maintenance expenses, fuel credits resulting from the Company's electric fuel cost adjustment clause discussed in Note 1 and gross receipts tax adjustments related to the FRA. At December 31, 1994 and 1993, the RMC balance was $463 million and $610 million, respectively. For a further discussion of the impact on the amortization of the RMC under the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) and the Company's Electric Rate Plan for the three year period beginning December 1, 1994, see Note 3.

On February 29, 1992, the Company transferred ownership of Shoreham to the Long Island Power Authority (LIPA), an agency of the State of New York. Pursuant to the 1989 Settlement, the Company has funded the decommissioning of Shoreham. Based on the latest available information, LIPA has reported that the cost of decommissioning Shoreham, which is essentially complete, totaled approximately $181 million, excluding the costs associated with the disposal of Shoreham's fuel which was also completed in 1994 and cost approximately $112 million. LIPA anticipates that the Nuclear Regulatory Commission (NRC) will terminate its license for Shoreham during 1995.

Note 3. Rate Matters

Electric

Long Island Lighting Company Ratemaking and Performance Plan

Pursuant to the 1989 Settlement, discussed in Note 2, the Company received electric rate increases as contemplated by the RMA for each of the three rate years in the period ended November 30, 1991. The RMA contemplates that the Company will apply to the PSC for targeted annual rate increases of 4.5% to 5.0% in each year for an eight year period beginning December 1, 1991. In November 1991, the PSC approved the LRPP which provided annual electric rate increases of 4.15%, 4.1% and 4.0%, respectively, for each of the three rate years in the period beginning December 1, 1991, with an allowed return on common equity from electric operations of 11.6% for each of the three rate years. After giving effect to the reductions required by the Class Settlement discussed in Note 4, the Company's annual electric rate increases were approximately 4.15%, 3.9% and 3.9%, with an allowed return on common equity from electric operations of 10.92%, 10.72% and 10.58%, for the rate years beginning December 1, 1991, 1992 and 1993, respectively.

The LRPP was designed to be consistent with the RMA's long term goals. One principal objective of the LRPP was to reassign risk so that the Company assumes the responsibility for risks within the control of management, whereas risks largely beyond the control of management would be assumed by the ratepayers. The LRPP reflects an update of the long range forecast of the Company's revenue requirements which was the basis of the RMA's initial three rate increases. The LRPP contains three major components — revenue reconciliation, expense attrition and reconciliation and performance incentives.

Revenue reconciliation is provided through a mechanism that eliminates the impact of experiencing electric sales that are above or below the LRPP forecast by providing a fixed annual net margin level (defined as sales revenues, net of fuel and gross receipts taxes) that the Company will receive under the LRPP. The differences between the actual electric net revenues and the annual net margin level are deferred on a monthly basis during the rate year.

The expense attrition and reconciliation component permits the Company to make adjustments for certain expenses recognizing that certain cost increases are unavoidable due to inflation and changes in the business. The LRPP includes the annual reconciliation of certain expenses for wage rates, property taxes, interest costs and demand side management (DSM) costs. The LRPP also provides for the deferral and amortization of certain costs for enhanced reliability and production operations and maintenance expenses and the application of an inflation index to other expenses for the rate years beginning December 1, 1992 and 1993.

Under the performance incentive component of the LRPP, the Company is allowed to earn for each rate year up to 60 additional basis points, or forfeit up to 38 basis points, of the allowed return on common equity as a result of its performance within certain incentive and/or penalty programs. These programs consist of a customer service program, a time of-use program, a partial pass through fuel cost incentive plan, a DSM program and, effective December 1, 1993, an electric transmission and distribution reliability plan. These incentives and/or penalties, except for incentives earned under the DSM program, are determined on a monthly basis during the rate year and deferred until final approval from the PSC. The incentives earned from the DSM program are collected in rates on a monthly basis through the FCA. Based upon the Company's performance within these programs, the Company earned a total of 50 and 49 basis points or approximately $9.2 million, net of tax effects, for each of the rate years ended November 30, 1994 and 1993. For the rate year ended November 30, 1992 the Company earned a total of 23 basis points or approximately $4.3 million, net of tax effects.

The deferred balances resulting from the net margin, property taxes, interest costs, wage rates, performance incentives and associated carrying charges, excluding DSM incentives, are netted at the end of each rate year. The LRPP established a band whereby the first $15 million of the total net deferrals are used to increase or decrease the RMC balance. The LRPP provides for the disposition of the total net deferrals in excess of the $15 million band. Upon approval by the PSC, the total net deferrals in excess of $15 million are refunded to or recovered from the ratepayers through the FCA over a twelve month period.

The Company recorded deferred balances of approximately $45.2 million, $63.1 million and $78.6 million of the total net deferrals for the rate years ended November 30, 1992, 1993 and 1994, respectively. The first $15 million of the total net deferrals has been recorded for the rate years ended November 30, 1992 and 1993 and upon approval by the PSC of the Company's reconciliation filing will be recorded for the rate year ended November 30, 1994 as an increase to the RMC with the remaining net deferrals of $30.2 million, $48.1 million and $63.6 million, respectively, recovered from the ratepayers through the FCA. As of July 31, 1994, the Company has fully collected the November 30, 1992 net deferrals through the FCA and is awaiting PSC approval for the collection of the 1993 and 1994 rate year net deferrals through the FCA. Effective August 1994, the PSC has allowed the Company to continue the collection of a like amount of the total net deferrals related to the rate year ended November 30, 1992 through the FCA. These additional revenues amounting to approximately $13.4 million through December 1994 were recorded as a reduction to the RMC. The Company expects to collect the 1993 rate year net deferrals of $48.1 million by November 30, 1995 and the 1994 rate year net deferrals of $63.6 million over the twelve month period ending November 30, 1996.

The LRPP contains a mechanism whereby earnings in excess of the allowed return on common equity of 11.6%, excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners. The Company earned $8.9 million and $21.4 million, net of tax effects, for the rate years ended November 30, 1993 and 1992, respectively, in excess of its allowed return on common equity. The amount in excess of the allowed return on common equity was shared equally between ratepayers (by a reduction to the RMC) and shareowners for the rate years ended November 30, 1993, and 1992. For the rate year ended November 30, 1994, the Company did not earn in excess of its allowed return on common equity.

To assist in the recovery of the RMC balance under the rates provided by the LRPP, the Company, in accordance with the LRPP, has credited the RMC with several deferred ratepayer benefits. In December 1994, the Company applied a total of approximately $5.1 million of net deferred ratepayer benefits to the RMC including DSM revenues overcollected in the 1994 rate year. In December 1993 and 1992, the Company reduced the RMC by approximately $10.1 million and $22.5 million representing various deferred ratepayer benefits including the ratepayers portion of the excess earnings for the rate years ended November 30, 1993 and 1992, respectively.

Electric Rate Plan
In December 1993, the Company filed a three year Electric Rate Plan with the PSC for the period beginning December 1, 1994 that minimizes future electric rate increases while retaining consistency with the RMA's objective of the restoration of the Company's financial health. The Electric Rate Plan requests an allowed return on common equity of 11.0% and provides for base rates to be frozen in years one and two and an overall rate increase of 4.3% in the third year. Although base electric rates would be frozen during the first two years of the Electric Rate Plan, annual rate increases of approximately 1% are expected to result from the operation of the Company's FCA. The FCA captures, among other things, amounts to be recovered from or refunded to ratepayers in excess of $15 million which result from the reconciliation of revenues, certain expenses and earned performance incentive components, discussed above.

The Company's Electric Rate Plan reflects four underlying objectives: (i) to limit the balance of RMC during the three year period to no more than its 1992 peak balance of $652 million; (ii) to recover the RMC within the time frame established in the 1989 Settlement; (iii) to minimize beginning in the third year of the Electric Rate Plan, the final three rate increases contemplated in the 1989 Settlement that follow the two year rate freeze period; and (iv) to continue the Company's gradual return to financial health.

The Electric Rate Plan provides for, with some modifications, the continuation of the LRPP revenue and expense reconciliations and performance incentives. The Electric Rate Plan includes the annual reconciliation of certain expenses for property taxes, interest costs, DSM costs and the deferral and amortization of certain costs for enhanced reliability. The Company would be allowed to earn for the three rate years under the Electric Rate Plan up to 50 additional basis points, excluding incentives under the DSM program, or forfeit up to 47 basis points of the allowed return on common equity of 11.0% as a result of the Company's performance within certain performance programs. These programs consist of a customer service program, a partial pass through fuel cost incentive plan, a DSM program and an electric transmission and distribution reliability plan.

The Company's Electric Rate Plan provides for lower annual electric rate increases than originally anticipated under the 1989 Settlement. However, as a result of changes in certain assumptions upon which the RMA was based, their impact on the RMC and the Company's plans to reduce DSM, operations and maintenance and capital expenditures, the Company has determined that the overall objectives of the RMA can be met under the Electric Rate Plan. As a result of lower than originally anticipated inflation rates, interest costs, property taxes, fuel costs and return on common equity allowed by the PSC, the RMC, which originally had been anticipated to peak at $1.2 billion in 1994, peaked at $652 million in 1992. With the exception of a projected increase in 1995 and 1996, which is not now anticipated to cause the RMC to increase above its $652 million peak, the RMC is expected to decline until it is fully amortized.

Under the Electric Rate Plan, the recovery of the RMC would be extended, if necessary, for an additional period of not more than three years beyond the approximate ten year period envisioned in the RMA. The actual length of the RMC extension will depend on the extent to which the assumptions underlying the Electric Rate Plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years.

The staff of the PSC (Staff) and other intervening parties filed testimony in response to the Company's Electric Rate Plan. Staff concurs with the Company's proposal for an 11.0% return on common equity in each of the three years and has reaffirmed its commitment to the principles of the RMA, including the full recovery of the RMC within the time frame established by the RMA. However, Staff has recommended an overall zero percent rate increase for the first two years, contrasted with the Company's proposal for a base rate freeze with FCA adjustments of approximately 1% in years one and two, as described above. Staff did not make a recommendation for the level of rate relief in the third year.

In September 1994, three Administrative Law Judges (ALJs) of the PSC issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposed 11.0% return on common equity and its proposal to freeze base electric rates for the first rate year. While no explicit recommendation was made concerning the second year, the recommended decision implies that base rates could remain frozen for the second rate year as well.

With respect to the third rate year beginning December 1, 1996, the ALJs determined that it was not appropriate for them to issue a recommendation since, in their opinion, the Company's revenue requirements for the third rate year cannot be precisely determined at this time. Alternatively, the ALJs encouraged the Company and other parties in this proceeding to negotiate a settlement concerning any rate increase for the third rate year.

The PSC had been expected to issue a final order on the Company's rate proposal before November 29, 1994, the date that the statutory suspension period was scheduled to terminate. However, in order to accommodate further settlement negotiations in the proceeding, the Company has requested extensions through April 1995, which were granted by the PSC. The Company's offers to extend the suspension period were conditioned upon the continuation of the current LRPP rate mechanisms. Although the ultimate outcome of the Electric Rate Plan cannot be predicted, the Company expects that any PSC order will be consistent with the provisions of the RMA respecting the recovery of the FRA and other 1989 Settlement deferred charges.

Gas

In December 1993, the PSC approved a three year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provides that the Company receive, for each of the rate years beginning December 1, 1993, 1994 and 1995, annual gas rate increases of 4.7%, 3.8% and 2.8%, respectively. An allowed return on common equity of 10.1% was used in the determination of the revenue requirements for the gas rate settlement. The gas rate decision also provides that earnings in excess of a 10.6% return on common equity in any of the three rate years covered by the settlement be shared equally between the Company's firm gas customers and its shareowners. For the rate year ended November 30, 1994, the Company earned $9.2 million, net of tax effects, in excess of the 10.6% return on common equity. The firm gas customers' portion of these excess earnings amounting to $4.6 million, net of tax effects, has been deferred until its final disposition is determined by the PSC.

Note 4. The Class Settlement

The Class Settlement, which became effective on June 28, 1989, resolved a civil lawsuit against the Company brought under the federal Racketeer Influenced and Corrupt Organizations Act. The lawsuit which the Class Settlement resolved had alleged that the Company made inadequate disclosures before the PSC concerning the construction and completion of nuclear generating facilities. The Class Settlement provides the Company's electric ratepayers with reductions, aggregating $390 million, that are being reflected as adjustments to their monthly electric bills over a ten year period which began on June 1, 1990.

The reductions which begin in each of the remaining twelve month periods are as follows:

June 1995	$40 million
June 1996	50 million
June 1997	60 million
June 1998	60 million
June 1999	60 million

Upon its effectiveness, the Company recorded its liability for the Class Settlement on a present value basis at $170 million and simultaneously recorded a charge to income (net of tax effects of $57 million) of approximately $113 million. Each month the Company records the changes in the present value of its liability that results from the passage of time and from monthly reductions. The Company expects the Class Settlement liability will be fully satisfied by May 31, 2000.

In accordance with the Class Settlement, the Company, in 1990, established a $10 million fund to reimburse former electric ratepayers entitled to refunds under the Class Settlement. At December 31, 1994, approximately $4.5 million remains undistributed in the fund. Pursuant to the terms of the Class Settlement, the undistributed portion of the net fund balance will be used to reduce ratepayers' bills upon the Company's receipt of the funds from the trustee.

Note 5. Nine Mile Point Nuclear Power Station, Unit 2

The Company has an 18% undivided interest in NMP2 which is operated by Niagara Mohawk Power Corporation (NMPC) near Oswego, New York. Ownership of NMP2 is shared by five cotenants: the Company (18%), NMPC (41%), New York State Electric & Gas Corporation (18%), Rochester Gas and Electric Corporation (14%) and Central Hudson Gas & Electric Corporation (9%). At December 31, 1994, the Company's utility plant investment in NMP2 was $749 million, net of accumulated depreciation of $140 million, which is included in the Company's rate base. Output of NMP2 is shared in the same proportions as the cotenants' respective ownership interests. The operating expenses of NMP2 are also allocated to the cotenants in the same proportions as their respective ownership interests. The Company's share of these expenses is included in the appropriate operating expenses on its Statement of Income. The Company is required to provide its respective share of financing for any capital additions to NMP2. Nuclear fuel costs associated with NMP2 are being amortized on the basis of the quantity of heat produced for the generation of electricity.

NMPC has contracted with the United States Department of Energy for the disposal of nuclear fuel. The Company reimburses NMPC for its 18% share of the cost under the contract at a rate of $1.00 per megawatt hour of net generation less a factor to account for transmission line losses.

The Company's share of the decommissioning costs for NMP2 is estimated to be $82 million and $234 million, in 1994 dollars and 2027 dollars, respectively, based upon a 1989 study performed by NMPC which was updated in 1993 to reflect a change in the NRC minimum decommissioning funding requirement. NMPC has informed the Company that decommissioning costs for NMP2 will increase primarily as a result of the inclusion of nuclear fuel storage charges and costs for continuing care. NMPC will be performing an updated decommissioning study for NMP2 in 1995. The Company will update its estimate for decommissioning costs upon the NRC's approval of the 1995 study. NMPC expects to commence decommissioning in 2027, shortly after cessation of operations, using a method which removes or decontaminates NMP2 components promptly. The Company's share of estimated decommissioning costs are being provided for in electric rates and are being charged to operations as depreciation expense over the expected service life of NMP2. The amount of decommissioning costs recorded as depreciation expense was $1.6 million in 1994 and $1.7 million in both 1993 and 1992. The accumulated decommissioning costs collected in rates through December 31, 1994 amounted to $8.7 million. The Company has established an independent decommissioning trust fund for the decommissioning of the contaminated portion of the NMP2 plant, which is approximately 92% of total decommissioning costs. As of December 31, 1994, the Company has accumulated $8.3 million in this external trust fund. Net earnings on this fund are recorded as an increase to accumulated depreciation. This fund complies with regulations issued by the NRC governing the funding of nuclear plant decommissioning costs.

Note 6. Capital Stock

Common Stock

During 1994, the Company issued 6.1 million shares of common stock, including the public offering in June of 5.1 million shares at $20 per share. The Company has 150,000,000 shares of authorized common stock, of which 118,416,606 were issued and outstanding at December 31, 1994. The Company has reserved 1,747,570 shares for sale through its Employee Stock Purchase Plan, 5,009,762 shares were committed to the Automatic Dividend Reinvestment Plan and 114,126 shares were reserved for conversion of the Series I Convertible Preferred Stock at a rate of $17.15 per share. Common and preferred stock dividend limitations in the mortgage securing the Company's First Mortgage Bonds are not material. There are no dividend limitations contained in the Company's other debt instruments.

Preferred Stock

The Company has 7,000,000 authorized shares, cumulative preferred stock, par value $100 per share and 30,000,000 authorized shares, cumulative preferred stock, par value $25 per share. Dividends on preferred stock are paid in preference to dividends on common stock or any other stock ranking junior to preferred stock.

Preferred Stock Subject to Mandatory Redemption

The aggregate fair value of redeemable preferred stock with mandatory redemptions at December 31, 1994 and 1993 amounted to approximately $564 million and $659 million, respectively, compared to their carrying amounts of $649 million and $654 million, respectively.

The Company is required to redeem each year certain series of preferred stock through the operation of sinking fund provisions as follows:

Series	Redemption Provision Beginning	Number of Shares	Redemption Price
L	July 31, 1979	10,500	$100
R	December 15, 1982	37,500	100
NN	March 1, 1999	77,700	25
UU	October 15, 1999	112,000	25

In addition, the Company will have the non-cumulative option to double the number of shares to be redeemed pursuant to the sinking fund provisions in any year for the preferred stock series R, NN and UU. The aggregate par value of preferred stock required to be redeemed through sinking funds in 1995 and 1996 is $4.8 million, in 1997 and 1998 is $1.1 million and in 1999 is $5.8 million.

The Company is also required to redeem all shares of certain series of preferred stock which are not subject to sinking fund requirements. The scheduled mandatory redemption for these series are as follows: (i) Series GG on March 1, 1999; (ii) Series AA on June 1, 2000; (iii) Series QQ on May 1, 2001 ; and (iv) Series CC on August 1, 2002.

Preferred Stock Not Subject to Mandatory Redemption
The Company has the option to redeem certain series of its preferred stock. For the series subject to optional redemption at December 31, 1994, the call prices were as follows:

Preferred Stock	*Call Price*
5.00% Series B	$101
4.25% Series D	102
4.35% Series E	102
4.35% Series F	102
5⅛% Series H	102
5¾% Series I — Convertible	100

Preference Stock
At December 31, 1994, none of the authorized 7,500,000 shares of nonparticipating preference stock, par value $1 per share, which ranks junior to preferred stock, were outstanding.

Note 7. Long-Term Debt

Each of the Company's outstanding mortgages is a lien on substantially all of the Company's properties.

First Mortgage
All of the bonds issued under the First Mortgage, including those issued after June 1, 1975 and pledged with the Trustee of the General and Refunding Mortgage (G&R Trustee) as additional security for General & Refunding Bonds (G&R Bonds), are secured by the lien of the First Mortgage. First Mortgage Bonds pledged with the G&R Trustee do not represent outstanding indebtedness of the Company. Amounts of such pledged bonds outstanding were $1.3 billion and $1.0 billion at December 31, 1994 and 1993, respectively. The annual First Mortgage depreciation fund and sinking fund requirements for 1994, due not later than June 30, 1995, are estimated at $239 million and $21 million, respectively. The Company expects to meet these requirements with property additions and retired First Mortgage Bonds.

G&R Mortgage
The lien of the G&R Mortgage is subordinate to the lien of the First Mortgage. The annual G&R Mortgage sinking fund requirement for 1994, due not later than June 30, 1995, is estimated at $26 million. The Company expects to satisfy this requirement with retired G&R Bonds.

1989 Revolving Credit Agreement
The Company has available through October 1, 1995, $300 million under its 1989 Revolving Credit Agreement (1989 RCA). This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories.

At December 31, 1994, no amounts were outstanding under the 1989 RCA. The Company has the option, when amounts are outstanding, to commit to one of three interest rates including: (i) the Adjusted Certificate of Deposit Rate which is a rate based on the certificate of deposit rates of certain of the lending banks, (ii) the Base Rate which is generally a rate based on Citibank, N.A.'s prime rate and (iii) the Eurodollar Rate which is a rate based on the London Interbank Offering Rate (LIBOR). The Company has agreed to pay a fee of one quarter of one percent per annum on the unused portion. The 1989 RCA may be extended for one year periods upon the acceptance by the lending banks of a request by the Company which must be delivered to the lending banks prior to April 1 of each year. It is the Company's intent to request an extension prior to April 1, 1995.

Authority Financing Notes
Authority Financing Notes are issued by the Company to the New York State Energy Research and Development Authority (NYSERDA) to secure certain tax-exempt Industrial Development Revenue Bonds, Pollution Control Revenue Bonds (PCRBs) and Electric Facilities Revenue Bonds (EFRBs) issued by NYSERDA. Certain of these bonds are subject to periodic tender at which time their interest rates may be subject to redetermination. Tender requirements of Authority Financing Notes at December 31, 1994 were as follows:

(In thousands of dollars)

Interest Rate	*Series*	*Principal*	
PCRBs			
8¼%	1982	$ 17,200	Tendered every three years, next tender October 1997
3.0%	1985 A,B	150,000	Tendered annually on March 1
EFRBs			
5.45%	1993 A	50,000	Tendered weekly
4.90%	1993 B	50,000	Tendered weekly
5.40%	1994 A	50,000	Tendered weekly

The 1994 and 1993 EFRBs and the 1985 PCRBs are supported by letters of credit pursuant to which the letter of credit banks have agreed to pay the principal, interest and premium, if applicable, in the aggregate, up to approximately $326 million in the event of default. The obligation of the Company to reimburse the letter of credit banks is unsecured. These letters of credit expire on October 26, 1997 for the 1994 EFRBs, November 17, 1996 for the 1993 EFRBs, and March 16, 1996 for the 1985 PCRBs, at each of which times the Company is required to obtain either an extension of the letters of credit or substitute credit backup. If neither can be obtained, the 1993 EFRBs, the 1994 EFRBs and the 1985 PCRBs must be redeemed unless the Company purchases them in lieu of redemption and subsequently remarkets them.

Fair Values of Long-Term Debt

The carrying amounts and fair values of the Company's long-term debt at December 31 were as follows:

(In thousands of dollars)

1994	*Fair Value*	*Carrying Amount*
First Mortgage Bonds	$ 95,688	$ 100,000
General and Refunding Bonds	1,844,289	1,951,000
Debentures	1,867,510	2,270,000
Authority Financing Notes	829,651	866,675
Total	$4,637,138	$5,187,675

1993	*Fair Value*	*Carrying Amount*
First Mortgage Bonds	$ 124,719	$ 125,000
General and Refunding Bonds	1,806,728	1,666,000
Debentures	2,944,499	2,880,058
Authority Financing Notes	851,800	816,675
Total	$5,727,746	$5,487,733

For a further discussion on the fair value of the securities listed above, see Note 1.

Maturity Schedule

Total long-term debt maturing in each of the next five years is $25 million (1995), $455 million (1996), $286 million (1997), $101 million (1998) and $454 million (1999).

Note 8. Retirement Benefit Plans

Pension Plans

The Company maintains a defined benefit pension plan which covers substantially all employees (Primary Plan), a supplemental plan which covers officers and certain key executives (Supplemental Plan) and a retirement plan which covers the Board of Directors (Directors' Plan). The Company also maintains 401(k) plans for its union and non-union employees. The Company does not contribute to these plans.

Primary Plan

The Company's funding policy is to contribute annually to the Primary Plan a minimum amount consistent with the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) plus such additional amounts, if any, as the Company may determine to be appropriate from time to time.

For service before January 1, 1992, pension benefits are determined based on the greater of the accrued benefit as of December 31, 1991, or by applying a moving five year average of Plan compensation, not to exceed the January 1, 1992 salary, to certain percentages as defined in the Primary Plan, determined by years of service at December 31, 1991. For service after January 1, 1992, pension benefits are equal to 2% per year of Plan compensation through age 49 and 2 1/2% thereafter. Employees are vested in the Primary Plan after five years of service with the Company.

The Primary Plan's funded status and amounts recognized on the Balance Sheet at December 31, 1994 and 1993 were as follows:

(In thousands of dollars)

	1994	*1993*
Actuarial Present Value of Benefit Obligation		
Vested benefits	**$ 467,962**	$ 468,797
Nonvested benefits	**50,385**	49,815
Accumulated Benefit Obligation	**$ 518,347**	$ 518,612
Plan assets at fair value	**$ 597,200**	$ 598,600
Actuarial present value of projected benefit obligation	**592,339**	597,128
Projected benefit obligation less than plan assets	**4,861**	1,472
Unrecognized net obligation	**84,577**	91,397
Unrecognized net gain	**(90,335)**	(97,029)
Net Accrued Pension Cost	**$ (897)**	$ (4,160)

Periodic pension cost for 1994, 1993 and 1992 for the Primary Plan included the following components:

(In thousands of dollars)

	1994	1993	1992
Service cost - benefits earned during the period	**$16,465**	$14,481	$13,661
Interest cost on projected benefit obligation and service cost	**43,782**	41,865	39,574
Actual return on plan assets	**(12,431)**	(54,010)	(47,156)
Net amortization and deferral	**(31,633)**	10,025	12,849
Net Periodic Pension Cost	**$16,183**	$12,361	$18,928

Assumptions used in accounting for the Primary Plan were as follows:

	1994	1993	1992
Discount rate	**7.75%**	7.25%	7.75%
Rate of future compensation increases	**5.0%**	5.0%	5.5%
Long-term rate of return on assets	**7.5%**	7.5%	7.5%

The Primary Plan assets at fair value include cash, cash equivalents, group annuity contracts, bonds and listed equity securities.

In 1993, the PSC issued an order which addressed the accounting and ratemaking treatment of pension costs in accordance with SFAS No. 87, Employers' Accounting for Pensions. Under the PSC order, the Company is required to recognize rate allowance deferred net gains or losses over a ten year period rather than using the corridor approach method. This change in the annual pension cost calculation reduced pension expense by $4.6 million in the year of adoption, 1993. The Company believes that this method of accounting for financial reporting purposes, results in a better matching of revenues and the Company's pension cost. The Company defers differences between pension rate allowance and pension expense under the PSC's order. In addition, the PSC requires the Company to measure the difference between the pension rate allowance and the annual pension contributions to the pension fund.

Supplemental Plan

The Supplemental Plan, the cost of which is borne by the Company's shareowners, provides supplemental death and retirement benefits for officers and other key executives without contribution from such employees. The Supplemental Plan is a non-qualified plan under the Internal Revenue Code. Death benefits are currently provided by insurance. The provision for plan benefits, which is unfunded, totaled approximately $2.3 million, $2.8 million and $.7 million which was recognized as expense in 1994, 1993 and 1992, respectively.

Directors' Plan

The Directors' Plan provides benefits to directors who are not officers of the Company. Directors who have served in that capacity for more than five years qualify as participants under the plan. The Directors' Plan is a non-qualified plan under the Internal Revenue Code. The provision for retirement benefits, which is unfunded, totaled approximately $148,000, $150,000 and $133,000 which was recognized as expense in 1994, 1993 and 1992, respectively.

Postretirement Benefits Other Than Pensions

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired employees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age after working for the Company for a minimum of five years. These and similar benefits for active employees are provided by the Company or by insurance companies whose premiums are based on the benefits paid during the year. Effective January 1, 1993, the Company adopted the provisions of SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, which requires the Company to recognize the expected cost of providing postretirement benefits when employee services are rendered rather than when paid. As a result, the Company, in 1993, recorded an accumulated postretirement benefit obligation and a corresponding regulatory asset of approximately $376 million. Additionally, as a result of adopting SFAS No. 106, the Company's postretirement benefit cost for 1993 increased by approximately $28 million above the amount that would have been recorded under the pay-as-you-go method.

In 1993, the PSC issued an order which required that the effects of implementing SFAS No. 106 be phased into rates. The order requires the Company to defer as a regulatory asset the difference between postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and the postretirement benefit expense reflected in rates. The ongoing annual postretirement benefit expense will be phased into and reflected in rates within a five year period with the accumulated postretirement obligation being recovered in rates over a twenty year period. In addition, the Company is required to recognize any deferred net gains or losses over a ten year period.

In 1994, the Company established Voluntary Employee's Beneficiary Association (VEBA) trusts for union and non-union employees for the funding of incremental costs collected in rates for postretirement benefits. In December 1994, the Company contributed $2.2 million for the incremental postretirement benefit cost collected in gas rates. In 1995, the Company will begin funding the incremental postretirement benefit cost for the electric business as these amounts are reflected in rates.

Accumulated postretirement benefit obligation other than pensions at December 31 was as follows:

	(In thousands of dollars)	
	1994	1993
Retirees	**$ 159,590**	$ 152,800
Fully eligible plan participants	**57,788**	63,800
Other active plan participants	**133,030**	137,200
Accumulated postretirement benefit obligation	**$ 350,408**	$ 353,800
Plan assets, cash	**(2,200)**	—
Accumulated postretirement benefit obligation in excess of plan assets	**348,208**	353,800
Unrecognized net gain	**73,936**	49,237
Accrued Postretirement Benefit Cost	**$ 422,144**	$ 403,037

Periodic postretirement benefit cost other than pensions for the years 1994, 1993 and 1992 was as follows:

	1994	1993	1992
Service cost – benefits earned during the period	**$ 11,275**	$ 12,980	$ —
Interest cost on projected benefit obligation and service cost	**25,713**	29,531	—
Amortization of net gain	**(5,213)**	—	—
Periodic Postretirement Benefit Cost	**$ 31,775**	$ 42,511	$ 13,400

Assumptions used to determine the postretirement benefit obligation were as follows:

	1994	1993
Discount rate	**7.75%**	7.25%
Rate of future compensation increases	**5.0%**	5.0%

The assumed health care cost trend rates used in measuring the accumulated postretirement benefit obligation at December 31, 1994 and 1993 were 9.0% and 9.5%, respectively, gradually declining to 6.0% in 2001 and thereafter. A one percentage point increase in the health care cost trend rate would increase the accumulated postretirement benefit obligation as of December 31, 1994 and 1993 by approximately $44 million and $46 million, respectively, and the sum of the service and interest costs in 1994 and 1993 by $6 million and $8 million, respectively.

Note 9. Federal Income Tax

At December 31, the significant components of the Company's deferred tax assets and liabilities calculated under the provisions of SFAS No. 109 were as follows:

	(In thousands of dollars)	
	1994	1993
Deferred Tax Assets		
Net operating loss carryforwards	**$ 552,917**	$ 707,400
Reserves not currently deductible	**86,267**	87,050
Tax depreciable basis in excess of book	**48,557**	59,147
Nondiscretionary excess credits	**31,933**	35,362
ITC carryforwards	**142,329**	142,329
Other	**89,763**	62,800
Total Deferred Tax Assets	**$ 951,766**	$ 1,094,088
Deferred Tax Liabilities		
1989 Settlement	**$ 2,174,729**	$ 2,180,413
Accelerated depreciation	**608,302**	597,827
Call premiums	**56,324**	63,735
Rate case deferrals	**55,598**	43,957
Other	**46,840**	46,097
Total Deferred Tax Liabilities	**$ 2,941,793**	$ 2,932,029
Net Deferred Tax Liability	**$ 1,990,027**	$ 1,837,941

Federal income tax expense in accordance with APB No. 11, for the year 1992 was as follows:

	(In thousands of dollars)
	1992
Federal Income Tax, per Statement of Income	
Current	$ 530
Deferred and other	
1989 Settlement	
Shoreham property	$ 3,806
Rate moderation component	10,351
Other 1989 Settlement items	8,622
Net operating loss carryforwards	(14,121)
Shoreham post settlement costs	60,125
Accelerated tax depreciation	35,951
Call premiums	35,441
Ratemaking and performance plan	17,680
Other items	2,577
Total Deferred and Other	$160,432
Total Federal Income Tax Expense	$160,962

The federal income tax amounts included in the Statement of Income differ from the amounts which result from applying the statutory federal income tax rate to income before income tax. The table below sets forth the reasons for such differences.

(In thousands of dollars)

	1994	*1993*	*1992*
Income before federal income tax	**$ 478,564**	$ 468,839	$ 462,936
Statutory federal income tax rate	**35%**	35%	34%
Statutory federal income tax	**$ 167,497**	$ 164,094	$ 157,398
Additions (Reductions) in Federal Income Tax			
1989 Settlement	**4,213**	4,256	4,003
AFC	**(2,450)**	(2,304)	(4,118)
Tax credits	**(6,837)**	(6,871)	(6,586)
Excess of book depreciation over tax depreciation	**14,745**	12,437	12,193
Interest capitalized	**2,449**	3,443	2,947
Other items	**(2,905)**	(2,779)	(4,875)
Total Federal Income Tax Expense	**$ 176,712**	$ 172,276	$ 160,962
Effective federal income tax rate	**36.9%**	36.7%	34.8%

The Company's net operating loss (NOL) carryforwards for federal income tax purposes is estimated to be approximately $1.6 billion at December 31, 1994. The NOL carryforwards will expire in the years 2004 through 2007. The amount of investment tax credit (ITC) carryforwards, net of the 35% reduction required by the Tax Reform Act of 1986, are approximately $142 million. The ITC carryforwards expire by the year 2005. For financial reporting purposes, a valuation allowance was not required to offset the deferred tax assets related to these carryforwards.

On January 8, 1990 and October 10, 1992, the Company received Revenue Agents' Reports disallowing certain deductions claimed by the Company on its tax returns for the audit cycle years 1984 through 1987 and 1988 through 1989, respectively. The Revenue Agents' Reports reflect proposed adjustments to the Company's federal income tax returns for 1984 through 1989 which, if sustained, would give rise to tax deficiencies totaling approximately $220 million. The Revenue Agents have proposed ITC adjustments which, if sustained, would reduce the Company's ITC carryforwards by approximately $96 million. The Company is protesting some of the adjustments and is seeking an administrative and, if necessary, a judicial review of the conclusions reached in the Revenue Agents' Reports. The Company cannot predict either the timing or the manner in which these matters will be resolved. If however, the ultimate disposition of any or all matters raised in the Revenue Agents' Reports are adverse to the Company, the Company expects that any deficiencies that may arise will be substantially offset by the net operating loss carrybacks associated with the 1989 Shoreham abandonment loss deduction of $1.8 billion and thus any impact would not have a material effect on the Company's financial condition or cash flows.

Note 10. Commitments and Contingencies

Commitments

The Company has entered into substantial commitments for gas supply, purchased power and transmission facilities. The costs associated with these commitments are recovered from ratepayers through provisions in the Company's rate schedules.

The Company expects that it will have to expend approximately $1 million in 1995 to meet continuous emission monitoring requirements and to meet Phase I nitrogen oxide (NOx) reduction requirements. Subject to requirements that are expected to be promulgated in forthcoming regulations, the Company estimates that it may be required to expend approximately $80 million (net of NOx credit sales) by 2003 to meet Phase II and Phase III NOx reduction requirements and approximately $24 million by 1999 to meet potential requirements for the control of hazardous air pollutants from power plants. The Company believes that all of the above costs will be recoverable through rates.

Contingencies

Environmental Matters

The Company is subject to federal, State and local laws and regulations dealing with air and water quality and other environmental matters. The Company continually monitors its activities in order to determine the impact of such activities on the environment and to ensure compliance with various environmental laws. Except as set forth below, no material proceedings have been commenced or, to the knowledge of the Company, are contemplated against the Company with respect to any matter relating to the protection of the environment.

The New York State Department of Environmental Conservation has indicated to New York State utilities that it may require all such utilities to investigate and, where necessary, remediate their former manufactured gas plant sites. The Company is the owner of six pieces of property on which the Company or certain of its predecessor companies produced manufactured gas. Although the exact amount of the Company's clean-up costs cannot yet be determined, based on the findings of investigations at two of these six sites, preliminary estimates indicate that it will cost approximately $35 million to clean up all of these sites over the next five to ten years. Accordingly, the Company has recorded a $35 million liability and has also recorded a $35 million regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these clean-up costs. However, the Company is unable to predict the amount of insurance recovery, if any, that it may obtain.

The Company has been notified by the Environmental Protection Agency (EPA) that it is one of many potentially responsible parties (PRPs) that may be liable for the remediation of three contaminated licensed treatment, storage and disposal sites. At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have completed a Remedial Investigation and Feasibility Study which is currently being reviewed by the EPA. The level of remediation required will be determined when the EPA issues its decision, currently expected in May 1995. The Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site. The Company believes that any cost incurred to remediate this site will be recoverable through rates.

With respect to the other two sites, which are located in Kansas City, Kansas and Kansas City, Missouri, the Company is investigating allegations that it had previously stored or made agreements for disposal of polychlorinated biphenyls (PCBs) or items containing PCBs at these sites. The Company is currently unable to determine its share of the cost to remediate these two sites or the impact, if any, on the Company's financial position. The Company believes that any cost incurred to remediate these sites will be recoverable through rates.

As a result of its daily business activity, the Company is involved in various legal and administrative proceedings, including other environmental proceedings. The Company believes the resolution of these proceedings will not have a material adverse effect on the Company's financial position or results of operations.

Nuclear Plant Insurance

The NRC requires the owners of nuclear facilities to maintain certain types of insurance. For property damage at each nuclear generating site, the NRC requires a minimum of $1.06 billion of coverage. The NRC has provided the Company with a partial exemption from these requirements for Shoreham. With respect to third party liability and property damage, the NRC requires nuclear plant owners to carry $200 million in primary coverage. Pursuant to these requirements, the Company carries property insurance and third party bodily injury and property liability insurance for its 18% share in NMP2 and for Shoreham. The annual premiums for this coverage are not material.

The policies also include retroactive premiums under certain circumstances. For the property damage policies, the retroactive premium assessments, on a per occurrence basis, could be as much as $4.6 million. Once Shoreham is declared a non-nuclear site by the NRC this retroactive premium assessment may decrease significantly.

For the third party liability and property damage insurance, the retroactive premium is related to the NRC's requirement that nuclear facility owners, in addition to carrying $200 million in primary coverage, also participate in a Secondary Financial Protection Fund (fund). Under the Price Anderson Act, that assessment related to the fund could be up to $79.3 million per nuclear incident in any one year at any nuclear unit, but not in excess of $10 million in payments per year for each incident. The Price Anderson Act also limits liability for third-party bodily injury and third-party property damage arising out of a nuclear occurrence at each unit to $8.9 billion.

In 1994, the NRC granted the Company permission to withdraw from the fund because Shoreham had been defueled. The withdrawal was effective November 18, 1994. The withdrawal relieves the Company from any retroactive premium assessment relating to any nuclear incident as of November 18, 1994 or later. The Company remains liable for retroactive assessments for any nuclear incident occurring prior to November 18, 1994 during the time the Company participated in the Fund because of its Shoreham ownership. As a co-owner of NMP2, the Company remains liable for 18% of any retroactive premium assessment levied against the NMP2 owners.

Note 11. Segments of Business

The Company is engaged in the electric and natural gas utility businesses. The Company serves residential, commercial and industrial customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens County, all on Long Island, New York. Identifiable assets by segment include net utility plant, regulatory assets, materials and supplies, accrued unbilled revenues, gas in storage, fuel and deferred charges. Assets utilized for overall Company operations consist primarily of cash and cash equivalents, accounts receivable and unamortized cost of issuing securities.

(In millions of dollars)

For year ended December 31	1994	1993	1992
Operating Revenues			
Electric	$ 2,481	$ 2,352	$ 2,195
Gas	586	529	427
Total	$ 3,067	$ 2,881	$ 2,622
Operating Expenses (excludes federal income tax)			
Electric	$ 1,640	$ 1,514	$ 1,355
Gas	500	427	353
Total	$ 2,140	$ 1,941	$ 1,708
Operating Income (before federal income tax)			
Electric	$ 842	$ 838	$ 840
Gas	85	102	74
Total operating income	927	940	914
AFC	(7)	(7)	(12)
Other income and deductions	(45)	(56)	(50)
Interest charges	500	534	513
Federal income tax	177	172	161
Net Income	$ 302	$ 297	$ 302
Depreciation and Amortization			
Electric	$ 112	$ 106	$ 104
Gas	19	16	15
Total	$ 131	$ 122	$ 119
Construction and Nuclear Fuel Expenditures*			
Electric	$ 155	$ 171	$ 164
Gas	125	134	109
Total	$ 280	$ 305	$ 27[illegible]

*Includes non-cash allowance for other funds used during construction.

At December 31	1994	1993	1992
Identifiable Assets			
Electric	$10,999	$11,194	$ 8,867
Gas	1,184	1,078	768
Total identifiable assets	12,183	12,272	9,635
Assets utilized for overall Company operations	1,034	1,121	1,129
Total Assets	$13,217	$13,393	$10,764

Note 12. Quarterly Financial Information

(Unaudited)

(In thousands of dollars except earnings per common share)

For quarter ended	1994	1993
Operating Revenues		
March 31	$ 872,143	$ 760,451
June 30	626,310	604,871
September 30	913,440	849,700
December 31	655,414	665,973
Operating Income		
March 31	$ 183,865	$ 192,391
June 30	139,478	167,599
September 30	276,965	263,984
December 31	144,637	131,577
Net Income		
March 31	$ 69,620	$ 67,861
June 30	24,787	56,806
September 30	168,872	144,549
December 31	38,573	27,347
Earnings for Common Stock		
March 31	$ 56,348	$ 53,286
June 30	11,516	42,451
September 30	155,620	131,022
December 31	25,348	13,696
Earnings per Common Share		
March 31	$ .50	$ .48
June 30	.10	.38
September 30	1.32	1.17
December 31	.21	.12

In the fourth quarter of 1993, the Company recorded income of approximately $6.5 million, net of tax effects, or $.06 per common share related to the settlement of certain litigation. In addition, in the fourth quarter of 1993, the Company recorded a charge to earnings of approximately $7.3 million, net of tax effects, or $.07 per common share principally related to previously deferred storm costs and the reconciliation of certain ratemaking mechanisms recorded in connection with the conclusion of the Company's rate year.

Report of Ernst & Young LLP, Independent Auditors

To the Shareowners and Board of Directors of Long Island Lighting Company

We have audited the accompanying balance sheet of Long Island Lighting Company and the related statement of capitalization as of December 31, 1994 and 1993 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. 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 in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Long Island Lighting Company at December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles.

Ernst + Young LLP

Melville, New York
February 3, 1995

Table 1 *(In thousands of dollars except per share amounts)*

Summary of Operations	1994	1993	1992	1991	1990
Revenues	**$ 3,067,307**	$ 2,880,995	$ 2,621,839	$ 2,547,729	$ 2,456,902
Operating expenses	**2,322,362**	2,125,444	1,880,734	1,762,449	1,654,272
Operating income	**744,945**	755,551	741,105	785,280	802,630
Other income and (deductions)	**52,719**	70,874	66,330	40,482	20,638
Income before interest charges and cumulative effect of accounting change	**797,664**	826,425	807,435	825,762	823,268
Interest charges and (credits)	**495,812**	529,862	505,461	520,224	503,631
Income before cumulative effect of accounting change	**301,852**	296,563	301,974	305,538	319,637
Cumulative effect of accounting change for unbilled gas revenues (net of tax)	**—**	—	—	—	11,680
Net income	**301,852**	296,563	301,974	305,538	331,317
Preferred stock dividend requirements	**53,020**	56,108	63,954	66,394	68,161
Earnings for Common Stock	**$ 248,832**	$ 240,455	$ 238,020	$ 239,144	$ 263,156
Average common shares outstanding (000)	**115,880**	112,057	111,439	111,348	111,290
Earnings per common share					
Before cumulative effect of accounting change	**$ 2.15**	$ 2.15	$ 2.14	$ 2.15	$ 2.26
Cumulative effect of accounting change	**—**	—	—	—	0.10
Earnings per Common Share	**$ 2.15**	$ 2.15	$ 2.14	$ 2.15	$ 2.36
Common stock dividends declared per share	**$ 1.78**	$ 1.76	$ 1.72	$ 1.60	$ 1.25
Common stock dividends paid per share	**$ 1.78**	$ 1.75	$ 1.71	$ 1.55	$ 1.125
Book value per common share at December 31	**$ 20.21**	$ 19.88	$ 19.58	$ 19.13	$ 18.57
Common shares outstanding at December 31 (000)	**118,417**	112,332	111,600	111,365	111,324
Common shareowners of record at December 31	**96,491**	94,877	86,111	90,435	82,903

Table 2

Capitalization Ratios*					
Long-term debt	**62.5%**	65.0%	64.7%	63.9%	62.2%
Preferred stock	**8.6**	8.5	8.8	8.8	9.4
Common equity	**28.9**	26.5	26.5	27.3	28.4
Total	**100.0%**	100.0%	100.0%	100.0%	100.0%

*Includes current maturities of long-term debt and current redemption requirements of preferred stock

Table 3 *(In thousands of dollars)*

Operations and Maintenance Expense Details					
Payroll and employee benefits	**$ 436,611**	$ 438,079	$ 413,817	$ 398,000	$ 357,689
Less — Charged to construction and other	**103,974**	116,988	124,076	123,838	97,650
Payroll and employee benefits charged to operations	**332,637**	321,091	289,741	274,162	260,039
Fuel and Purchased Power					
Fuel — electric operations	**261,154**	287,349	282,138	354,859	447,481
Fuel — gas operations	**267,629**	253,511	206,344	172,992	185,474
Purchased power costs	**307,584**	292,136	280,914	197,154	168,749
Fuel cost adjustments deferred	**11,619**	(5,405)	(27,612)	43,697	(14,705)
Total fuel and purchased power	**847,986**	827,591	741,784	768,702	786,999
All other	**208,017**	200,569	208,204	248,597	215,770
Total Operations and Maintenance Expense	**$ 1,388,640**	$ 1,349,251	$ 1,239,729	$ 1,291,461	$ 1,262,808
Full-time employees at December 31	**5,947**	6,215	6,438	6,538	6,545

Table 4

(In thousands of dollars)

Electric Operating Income	1994	1993	1992	1991	1990
Revenues					
Residential	**$1,202,124**	$1,145,891	$1,045,799	$1,047,490	$ 997,868
Commercial and industrial	**1,196,422**	1,132,487	1,076,302	1,070,098	1,017,387
Other system revenues	**52,477**	49,790	49,395	47,838	46,673
Total system revenues	**2,451,023**	2,328,168	2,171,496	2,165,426	2,061,928
Sales to other utilities	**14,895**	12,872	9,997	23,040	24,140
Other revenues	**15,719**	11,069	13,139	8,102	9,592
Total Revenues	**2,481,637**	2,352,109	2,194,632	2,196,568	2,095,660
Operating Expenses					
Operations — fuel and purchased power	**568,738**	579,032	559,583	593,656	611,122
Operations — other	**310,438**	306,116	294,909	296,798	271,608
Maintenance	**107,573**	111,765	105,341	127,446	118,545
Depreciation and amortization	**111,996**	106,149	104,034	104,172	98,022
Base financial component amortization	**100,971**	100,971	100,971	100,971	100,971
Rate moderation component amortization	**197,656**	88,667	(30,444)	(228,572)	(297,214)
Regulatory liability component amortization	**(79,359)**	(79,359)	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	**(9,214)**	(9,214)	(9,214)	(9,214)	(9,214)
Other regulatory amortization	**(4,883)**	(17,082)	(21,984)	10,375	14,427
Operating taxes	**336,263**	326,407	331,122	338,429	322,197
Federal income tax — current	**10,784**	6,324	530	515	3,138
Federal income tax — deferred and other	**156,646**	158,941	158,908	173,259	169,274
Total Operating Expenses	**1,807,609**	1,678,717	1,514,397	1,428,476	1,323,517
Electric Operating Income	**$ 674,028**	$ 673,392	$ 680,235	$ 768,092	$ 772,143

Table 5

(In thousands of dollars)

Gas Operating Income	1994	1993	1992	1991	1990
Revenues					
Residential — space heating	**$ 326,474**	$ 310,109	$ 243,950	$ 190,976	$ 198,734
Residential — other	**42,263**	39,515	33,035	29,383	30,854
Commercial and industrial — space heating	**126,092**	106,140	90,363	70,938	68,441
Commercial and industrial — other	**35,275**	33,181	29,094	25,515	26,501
Total firm revenues	**530,104**	488,945	396,442	316,812	324,530
Interruptible revenues	**26,804**	24,028	19,658	21,686	30,515
Total system revenues	**556,908**	512,973	416,100	338,498	355,045
Other revenues	**28,762**	15,913	11,107	12,663	6,197
Total Revenues	**585,670**	528,886	427,207	351,161	361,242
Operating Expenses					
Operations — fuel	**279,248**	248,559	182,201	175,046	175,877
Operations — other	**95,576**	81,692	77,300	78,469	68,910
Maintenance	**27,067**	22,087	20,395	20,046	16,746
Depreciation and amortization	**18,668**	16,322	15,103	14,783	12,862
Regulatory amortization	**9,211**	(962)	(88)	—	—
Operating taxes	**70,632**	59,440	57,866	49,951	48,120
Federal income tax — current	**—**	—	—	—	500
Federal income tax — deferred and other	**14,351**	19,589	13,560	(4,322)	7,740
Total Operating Expenses	**514,753**	446,727	366,337	333,973	330,755
Gas Operating Income	**$ 70,917**	$ 82,159	$ 60,870	$ 17,188	$ 30,487

Table 6

Electric Sales and Customers	1994	1993	1992	1991	1990
Sales — millions of kWh					
Residential	**7,159**	7,118	6,788	7,022	7,022
Commercial and industrial	**8,394**	8,257	8,181	8,322	8,359
Other	**457**	449	471	469	472
System sales	**16,010**	15,824	15,440	15,813	15,853
Sales to other utilities	**372**	304	227	598	532
Total Sales	**16,382**	16,128	15,667	16,411	16,385
Customers — monthly average					
Residential	**908,490**	905,997	902,885	898,974	895,294
Commercial and industrial	**102,490**	102,254	101,838	101,740	101,562
Other	**4,583**	4,553	4,593	4,540	4,504
Total Customers — monthly average	**1,015,563**	1,012,804	1,009,316	1,005,254	1,001,360
Customers — at December 31	**1,016,739**	1,011,965	1,009,028	1,005,363	1,001,441
Residential					
kWh per customer	**7,880**	7,856	7,518	7,811	7,843
Revenue per kWh	**16.79¢**	16.10¢	15.41¢	14.92¢	14.21¢
Commercial and Industrial					
kWh per customer	**81,901**	80,750	80,333	81,797	82,304
Revenue per kWh	**14.25¢**	13.72¢	13.16¢	12.86¢	12.17¢
System					
kWh per customer	**15,765**	15,624	15,297	15,731	15,832
Revenue per kWh	**15.31¢**	14.71¢	14.06¢	13.69¢	13.01¢

Table 7

Gas Sales and Customers	1994	1993	1992	1991	1990
Sales — thousands of dth					
Residential — space heating	**35,693**	37,191	35,089	29,687	29,810
Residential — other	**3,151**	3,297	3,203	3,195	3,443
Commercial and industrial — space heating	**15,679**	14,366	13,662	11,636	11,271
Commercial and industrial — other	**4,366**	4,329	4,338	4,171	4,352
Total firm sales	**58,889**	59,183	56,292	48,689	48,881
Interruptible sales	**6,914**	5,920	5,090	4,538	6,347
Off-system sales	**7,232**	2,894	—	—	—
Total Sales	**73,035**	67,997	61,382	53,227	55,228
Customers — monthly average					
Residential — space heating	**239,857**	233,882	227,834	220,562	211,400
Residential — other	**163,608**	166,974	169,189	171,581	176,000
Commercial and industrial — space heating	**33,776**	32,783	31,666	30,453	29,072
Commercial and industrial — other	**10,448**	10,631	10,777	11,003	11,310
Total firm customers	**447,689**	444,270	439,466	433,599	427,782
Interruptible customers	**576**	542	531	472	410
Total Customers — monthly average	**448,265**	444,812	439,997	434,071	428,192
Customers — at December 31	**449,906**	446,384	442,117	436,853	430,571
Residential					
dth per customer	**96.3**	101.0	96.4	83.9	85.8
Revenue per dth	**$ 9.49**	$ 8.64	$ 7.23	$ 6.70	$ 6.90
Commercial and Industrial					
dth per customer	**453.3**	430.6	424.1	381.3	386.9
Revenue per dth	**$ 8.05**	$ 7.45	$ 6.64	$ 6.10	$ 6.08
System					
dth per customer	**146.8**	146.4	139.5	122.6	128.9
Revenue per dth	**$ 8.46**	$ 7.88	$ 6.78	$ 6.36	$ 6.43

Table 8

Electric Operations	**1994**	1993	1992	1991	1990
Energy — millions of kWh					
Net generation	**10,034**	10,514	10,592	13,570	13,981
Power purchased	**7,640**	7,023	6,438	4,236	3,521
Total Energy Available	**17,674**	17,537	17,030	17,806	17,502
System sales	**16,010**	15,824	15,440	15,813	15,853
Company use and unaccounted for	**1,292**	1,409	1,363	1,395	1,117
Total system energy requirements	**17,302**	17,233	16,803	17,208	16,970
Sales to other utilities	**372**	304	227	598	532
Total Energy Available	**17,674**	17,537	17,030	17,806	17,502
Peak Demand — MW					
Station coincident demand	**3,253**	2,931	2,975	3,085	3,260
Power purchased — net	**629**	1,036	636	819	426
System Peak Demand	**3,882**	3,967	3,611	3,904	3,686
System Capability — MW					
Company stations	**4,063**	4,063	4,091	4,078	4,077
Nine Mile Point 2 (18% share)	**189**	188	188	194	194
Firm purchases — net	**616**	548	432	423	408
Total Capability	**4,868**	4,799	4,711	4,695	4,679
Fuel Consumed for Electric Operations					
Oil — thousands of barrels	**7,518**	9,740	[illegible]	15,314	16,401
Gas — thousands of dth	**44,308**	36,269	[illegible]	32,924	36,477
Nuclear — thousands of MW days	**183**	181	[illegible]	154	108
Total — billions of Btu	**91,669**	98,025	102,126	129,937	139,874
Dollars per million Btu	**$ 2.69**	$ 2.79	$ 2.62	$ 2.61	$ 3.07
Cents per kWh of net generation	**2.88¢**	2.97¢	2.76¢	2.73¢	3.24¢
Heat rate — Btu per net kWh	**10,740**	10,628	10,558	10,484	10,564
Fuel Mix (Percentage of system requirements)					
Oil	**25%**	33%	37%	50%	56%
Gas	**23**	19	19	18	20
Purchased power	**43**	41	38	25	20
Nuclear fuel	**9**	7	6	7	4
Total	**100%**	100%	100%	100%	100%

Table 9

Gas Operations					
Energy — thousands of dth					
Natural gas	**75,360**	69,970	64,911	55,579	55,407
Manufactured gas and change in storage	**191**	(68)	48	60	(15)
Total Company Requirements	**75,551**	69,902	64,959	55,639	55,392
System sales	**65,803**	65,103	61,382	53,227	55,228
Off-system sales	**7,232**	2,894	—	—	—
Company use and unaccounted for	**2,516**	1,905	3,577	2,412	164
Total Company Requirements	**75,551**	69,902	64,959	55,639	55,392
Maximum Day Sendout — dth	**585,227**	485,896	448,726	435,050	406,177
System Capability — dth per day					
Natural gas	**579,897**	561,584	561,584	507,344	507,344
LNG manufactured or LP gas	**125,700**	120,700	120,700	128,200	128,200
Total Capability	**705,597**	682,284	682,284	635,544	635,544
Calendar Degree Days (30 year average 4,797)	**4,839**	4,899	5,066	4,378	4,139

Table 10 *(In thousands of dollars)*

Balance Sheet	1994	1993	1992	1991	1990
Assets					
Net utility plant	**$ 3,498,346**	$ 3,347,5[illegible]7	$ 3,161,148	$ 3,002,733	$ 2,888,079
Regulatory assets					
Base financial component	**3,483,490**	3,5[illegible]4,461	3,685,432	3,786,403	3,887,373
Rate moderation component	**463,229**	609,827	651,657	602,053	411,443
Shoreham post settlement costs	**922,580**	777,103	586,045	378,386	225,818
Shoreham nuclear fuel	**73,371**	75,497	77,629	79,760	92,069
Postretirement benefits other than pensions	**412,727**	402,921	—	—	—
Regulatory tax asset	**1,831,689**	1,848,998	—	—	—
Other	**354,524**	311,832	220,380	104,484	106,654
Total Regulatory Assets	**7,541,610**	7,610,639	5,221,143	4,951,086	4,723,357
Nonutility property and other investments	**24,043**	23,029	20,730	9,788	6,381
Current assets	**851,424**	924,859	916,914	884,017	726,060
Deferred charges	**1,301,257**	1,487,032	1,444,524	1,290,871	1,173,361
Total Assets	**$ 13,216,680**	$13,393,116	$10,764,459	$10,138,495	$ 9,517,238
Capitalization and Liabilities					
Long-term debt	**$ 5,162,675**	$ 4,887,733	$ 4,755,733	$ 5,001,016	$ 4,556,016
Unamortized discount on debt	**(17,278)**	(17,393)	(14,731)	(14,850)	(23,125)
	5,145,397	4,870,340	4,741,002	4,[illegible]86,166	4,532,891
Preferred stock — redemption required	**644,350**	649,150	5[illegible]7,900	524,912	527,550
Preferred stock — no redemption required	**63,957**	64,038	154,276	154,371	154,674
Total Preferred Stock	**708,307**	713,188	712,176	679,283	682,224
Common stock	**592,083**	561,662	558,002	556,825	556,620
Premium on capital stock	**1,101,24[illegible]**	1,010,283	998,089	993,509	992,885
Capital stock expense	**(52,175)**	(50,427)	(39,304)	(40,216)	(42,676)
Retained earnings	**752,480**	711,432	667,988	620,373	560,405
Total Common Shareowners' Equity	**2,393,628**	2,232,950	2,184,775	2,130,491	2,067,234
Total Capitalization	**8,247,332**	7,816,478	7,637,953	7,795,940	7,282,349
Regulatory Liabilities					
Regulatory liability component	**357,117**	436,476	515,835	595,194	674,554
1989 Settlement credits	**145,868**	155,081	164,294	173,507	182,720
Regulatory tax liability	**111,218**	114,748	—	—	—
Other	**143,611**	138,612	100,470	72,277	102,655
Total Regulatory Liabilities	**757,814**	844,917	780,599	840,978	959,929
Current liabilities	**605,478**	1,188,972	1,181,297	492,895	449,830
Deferred credits	**3,102,434**	3,109,593	1,147,310	1,001,375	816,790
Operating reserves	**503,622**	433,156	17,300	7,307	8,340
Total Capitalization and Liabilities	**$ 13,216,680**	$13,393,116	$10,764,459	$10,138,495	$ 9,517,238

Table 11 *(In thousands of dollars)*

Construction Expenditures*	1994	1993	1992	1991	1990
Electric	**$ 136,041**	$ 137,583	$ 141,752	$ 129,643	$ 141,028
Gas	**120,019**	124,859	104,028	89,950	78,766
Common	**23,610**	42,251	27,124	17,958	12,671
Total Construction Expenditures	**$ 279,670**	$ 304,693	$ 272,904	$ 237,551	$ 232,465

*Includes non-cash allowance for other funds used during construction

Executive Offices
175 East Old Country Road
Hicksville, New York 11801
516-755-6650

Common Stock Listed
New York Stock Exchange
Pacific Stock Exchange

Ticker Symbol: LIL

Transfer Agent and Registrar
Common Stock and Preferred Stock
The Bank of New York
Shareholder Services Department
Church Street Station
P.O. Box 11277
New York, NY 10286-1612
1-800-524-4458

Shareowners' Agent for Automatic Dividend Reinvestment Plan
The Bank of New York
Dividend Reinvestment Department
Church Street Station
P.O. Box 11277
New York, NY 10286-1612
1-800-524-4458

Dividend Reinvestment
Common stock shareowners who wish to acquire additional shares free of brokerage commissions or service charges are invited to join the Company's Automatic Dividend Reinvestment Plan. Under the plan, shareowners authorize the Company's transfer agent to purchase shares of the Company's common stock with their cash dividends. Shareowners may also participate in the plan by making optional cash payments, even if they decide not to reinvest their dividends. For further information, contact our transfer agent.

Dividend Direct Deposit
Shareowners can elect to have their quarterly cash dividends electronically deposited into their personal bank accounts. Deposits are made on the date the dividend is payable. If you would like to take advantage of this service, contact our transfer agent.

Annual Meeting
The Annual Meeting of Shareowners will be held on Wednesday, May 24, 1995 at 3:00 p.m. In connection with this meeting, proxies will be solicited by the Company.

Common Stock Prices and Dividends
The common stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. Certain of the Company's preferred stock series are traded on the New York Stock Exchange. The quoted market prices and the dividends declared for the Company's common stock for the years 1994 and 1993 were as follows.

Quarter			**1994**			*1993*
	High	**Low**	**Dividend**	*High*	*Low*	*Dividend*
First	**$24¼**	**$21½**	**$.445**	$28¾	$24⅞	$.435
Second	**22⅞**	**17½**	**.445**	28¼	24¾	.435
Third	**19⅜**	**15**	**.445**	29⅝	27	.445
Fourth	**18⅛**	**15¼**	**.445**	27¾	23¼	.445

Form 10-K Annual Report
The Company will furnish, without charge, a copy of the Company's Annual Report, Form 10-K, as filed with the Securities and Exchange Commission, upon written request to:

Investor Relations
Long Island Lighting Company
175 East Old Country Road
Hicksville, New York 11801

Our Investor Relations Department is available from 8:00 a.m. to 5:00 p.m., Monday through Friday to answer any questions you may have about your LILCO stock. If you have a question, please call us at 516-545-4914.

Duplicate Mailings
Shareowners with more than one account generally receive duplicate mailings of annual and other reports. To eliminate additional mailings, write to our transfer agent. Enclose labels or label information, where possible. Separate dividend checks and proxy material will continue to be sent for each account of record.

LILCO uses recycled paper to help conserve our natural resources.

Long Island Lighting Company
175 East Old Country Road
Hicksville, New York 11801

DIRECTORS

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer
Long Island Lighting Company

A. James Barnes
Dean
School of Public and
Environmental Affairs
Indiana University

George Bugliarello
Chancellor
Polytechnic University

Renso L. Caporali
Former Chairman of the Board
and Chief Executive Officer
Grumman Corporation

Peter O. Crisp
President
Venrock, Inc.
Venture Capital Investments

Vicki L. Fuller
Senior Vice President
Emerging Markets
and High Yield
Alliance Capital Management
Corporation

Katherine D. Ortega
Former Treasurer
of the United States

Basil A. Paterson
Partner
Meyer, Suozzi, English
& Klein, PC
Law

Richard L. Schmalensee
Director
Center for Energy and
Environmental Policy Research
Massachusetts Institute
of Technology

George J. Sideris
Retired Senior Vice President
Finance
Long Island Lighting Company

John H. Talmage
Partner
H.R. Talmage & Son
Agriculture

Phyllis S. Vineyard
Representative to
Non-Governmental
Organization of
the United Nations

OFFICERS

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer

James T. Flynn
Executive Vice President
and Chief Operating Officer

Arthur C. Marquardt
Senior Vice President
Gas Business Unit

Anthony Nozzolillo
Senior Vice President Finance
and Chief Financial Officer

Edward J. Youngling
Senior Vice President
Electric Business Unit

Robert X. Kelleher
Vice President
Human Resources

John D. Leonard, Jr.
Vice President
Engineering and
Construction

Adam M. Madsen
Vice President
Corporate and
Strategic Planning

Kathleen A. Marion
Vice President
Corporate Services
and Corporate Secretary

Brian R. McCaffrey
Vice President
Administration

Joseph W. McDonnell
Vice President
External Affairs

Richard Reichler
Vice President
Tax and Benefits Planning
and Deputy General Counsel

William G. Schiffmacher
Vice President
Customer Relations

Robert B. Steiger
Vice President
Electric Operations

William E. Steiger, Jr.
Vice President
Fossil Production

Leonard P. Novello
General Counsel

Theodore A. Babcock
Treasurer

Joseph E. Fontana
Controller

Herbert M. Lampen
Assistant General Counsel
and Assistant Corporate
Secretary

Long Island Lighting Company
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