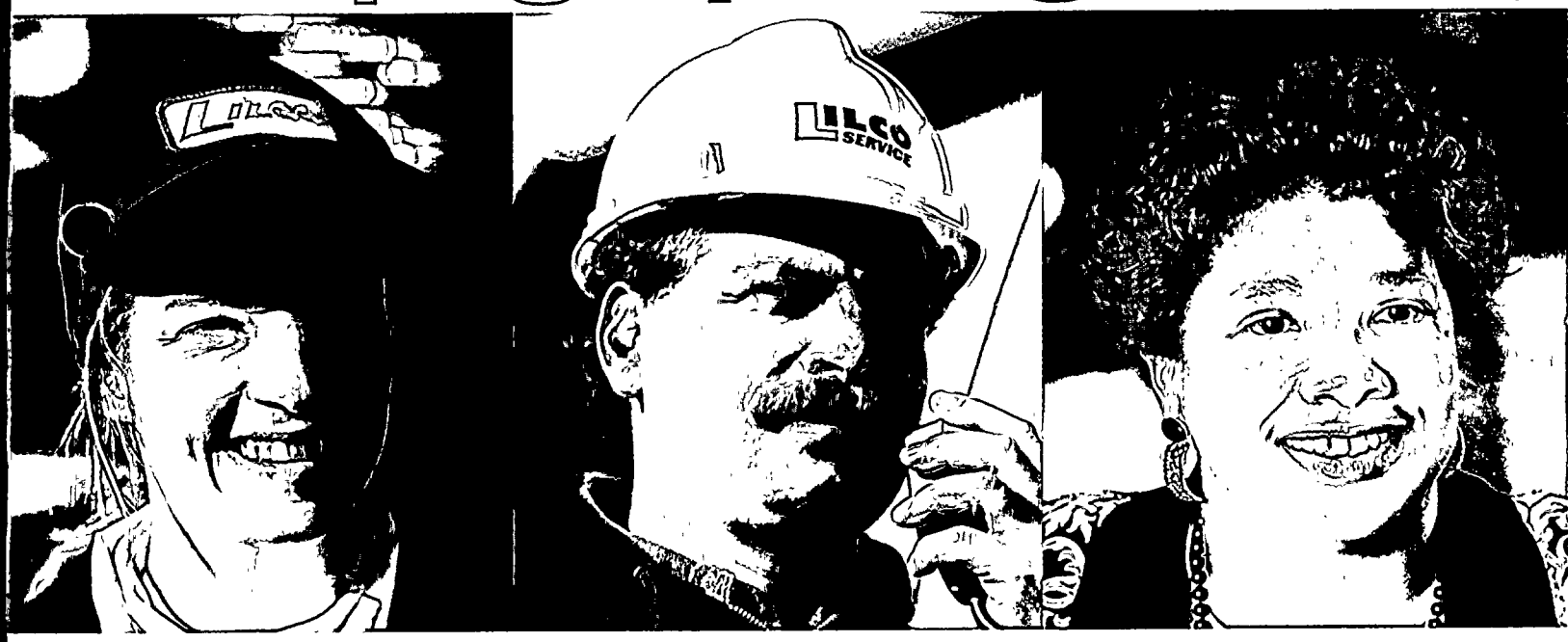
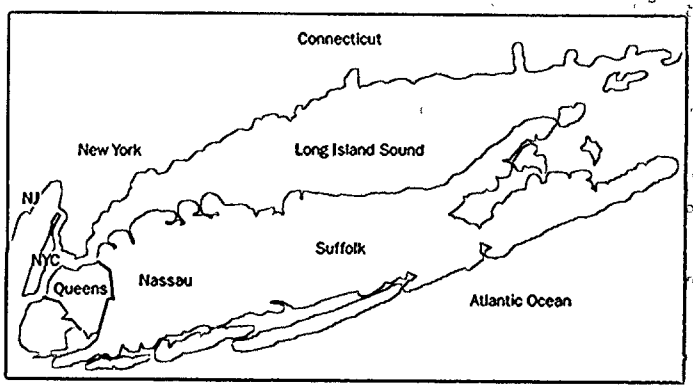
Competing Serving Responding Developing Improving Adapting



Long Island Lighting Company Annual Report 1993

The Long Island Lighting Company's 6,300 employees provide electric and gas service to more than 1 million customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens County. LILCO's service territory covers 1,230 square miles with a population of approximately 2.7 million people.



☐ Territory served by Long Island Lighting Company

1993 Highlights

- Common stock dividend increased for fourth consecutive year.
- Set a new record for peak electric consumption of 3,967 megawatts on July 9.
- Refinanced $983 million of high cost debt and equity securities saving $18 million annually.
- Added more than 9,000 new gas heat customers.

To Our Shareowners

1993 was a year in which LILCO's financial health continued to improve. Earnings for the year were $240 million or $2.15 per common share, and we increased our quarterly common stock dividend by 2.3 percent to 44.5 cents per share, effective October 1, 1993.

During the year, we made significant strides toward fulfilling our vision of the future, a future challenged by the competing demands to lower costs and improve service. The company began to set in motion its blueprint for success with an emphasis on performance and service. We have worked hard to lower costs by improving efficiency and taking advantage of changing market conditions and new opportunities.

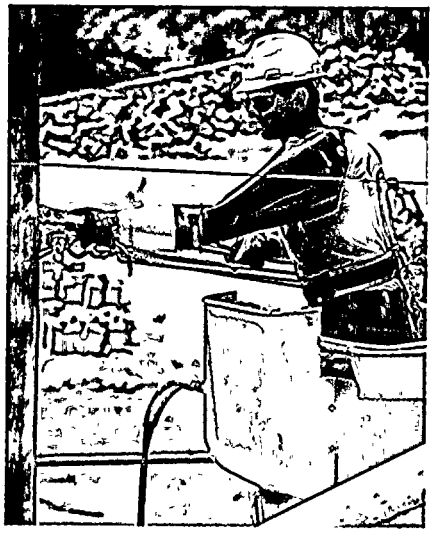
These efforts have resulted in a major accomplishment — the company's latest rate plan, filed on December 31, 1993. The plan proposes to freeze base electric rates for the next two years, holding base rates at current levels through November, 1996.

LILCO has taken this action now to help revitalize the Long Island economy and to help better position the company to deal with the trend toward competition. We believe we can accomplish this significant task while continuing to return the company to financial health under the plan set out in the Shoreham settlement agreement. The following factors have allowed us to propose this rate freeze:

Lower operating and capital costs. We are containing costs with tight budget control over expense and capital items. By operating more efficiently, we have been able to streamline our work force five percent through attrition over the last two years and plan to reduce it another five percent by the end of 1995. We have reduced overtime, implemented a managed health care program, and improved the reliability of our power plants. These, and other, cost-containment programs, combined with a low inflation rate, have allowed the company to save $130 million in the last four years.

Lower interest rates. Over the last few years, LILCO has taken full advantage of lower interest rates available to the company with a comprehensive refinancing program. Since 1989, the company has refinanced more than $4 billion of high cost debt, saving LILCO and its customers approximately $88 million annually.

Lower fuel and power costs. A drop in oil prices, the conversion of power plants from oil-fired to natural gas fuel and the availability of excess low-cost power from off Long Island have helped to hold down the cost of electricity. Today, only 33 percent of the energy provided to LILCO customers is generated by burning oil. Natural gas and purchased power play a much greater role in providing electricity to customers.



Lower property taxes. LILCO remains the largest taxpayer on Long Island. State, county and local taxes paid by the company in 1993 exceeded $595 million. Nevertheless, LILCO's property tax payments are less than they were anticipated to be under the Shoreham settlement because taxes have not escalated at the projected rate, and the courts have determined that some utility property had been overassessed.

Reduced conservation costs. With additional power plants and another interconnection to import power from upstate, LILCO now has ample electricity to meet energy requirements for the next decade. While continuing to view conservation as a solution to ease energy demand and as a key element in economic development, the company can scale back expensive incentive programs that pay customers to conserve.

We are mindful of our high electric rates, and we are taking this step to freeze base electric rates to send a clear signal to our customers and the financial community that we can control rates and help improve the long-term economic future of the company and the community.

We want to become energy "partners" with our customers by providing the expertise they need to succeed here on Long Island. With special energy packages and information services, LILCO is helping customers and potential customers relocate, expand, and improve their operations on Long Island. We will be introducing value-added services such as individual account managers for LILCO's largest customers and "one-stop-shopping" to expedite all customer inquiries as part of our program to provide unparalleled service to our customers.

We believe these measures, combined with our base rate freeze, favorably position the company for long-term success. The rating agencies have become increasingly concerned about changes in the utility industry and have imposed stricter standards on utilities. In December, following a review of the utility industry in general, Standard & Poor's rating agency downgraded the securities of many utilities, including those of LILCO. While Duff and Phelps lowered its ratings on LILCO's preferred stock and debentures, it reaffirmed its ratings on the company's first mortgage and general and refunding bonds. LILCO's ratings by Moody's and Fitch have remained the same.

LILCO's proposed rate plan calls for the company to aggressively control costs and gradually improve its debt-to-equity ratio. We believe these actions will stabilize our current securities ratings and eventually result in higher ratings.

On behalf of the company's Board of Directors and officers, I would like to thank you, our shareowner, for your past and continuing interest in LILCO.

Sincerely,

W. J. Catacosinos

William J. Catacosinos
Chairman, President and Chief Executive Officer

Lynda Thompson is helping LILCO save time and money. She's one of the company's meter readers now using ITRON, the most advanced hand-held data recording device in the industry. This state-of-the-art equipment operates faster and more accurately than previous models. ►

Developing

LILCO invests in research and development to improve production, delivery and conservation of electricity and natural gas. It's an important part of reducing expenses. For every dollar invested in R&D, LILCO expects a $3 return in more cost efficient operations. ► LILCO has enhanced these returns through the Long Island Energy Research and Development Initiative. The initiative unites Long Island academic and business organizations, tapping into the vast local supply of innovative technology and talent. Such partnerships have yielded improved training techniques, new gas leak detection devices, and an additive to help detect lost coolant in commercial refrigeration. These projects improve efficiency and cut costs — good news for customers and shareowners.


LILCO

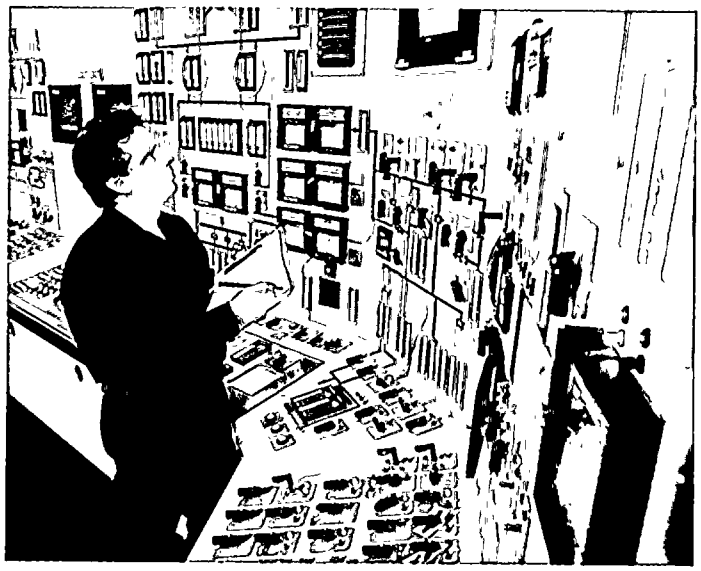
◄ Keeping tabs on world events that might affect oil prices is one of the ways Fuels Supply Manager Jimmy Huie plans LILCO's oil purchases. Searching for the lowest possible prices, Huie and his team carefully monitor supplies, negotiate competitive contracts, and maintain constant contact with oil dealers and brokers on the lookout for low-cost oil available on the spot market. Last year their efforts saved LILCO and its customers more than $4.1 million.

Responding

On a daily, and sometimes hourly basis, LILCO electric system operators act as "power" brokers, determining the most economic mix of fuels and generating units to supply electric service to customers at the lowest possible cost. Many times, this action includes purchasing power from other utilities instead of producing it in our own plants. Last year, such purchases saved the company more than $100 million. ► The fuel oil LILCO uses to generate electricity cost $180 million in 1993. That's one of the reasons why LILCO carefully designs its oil purchasing practices to get the lowest cost possible.

With a greater supply of gas entering Long Island through the Iroquois pipeline, LILCO has been able to increase its use of this clean-burning, economical fuel. Control Operator Randy Scott monitors fuel levels at the company's Northport Power Station Unit 4, recently converted to dual-fuel burning capability. The conversion enables LILCO to react to market changes and respond by burning either oil or gas, whichever is more economical. The company expects to save millions of dollars annually from the conversion.

Competing



A recent order by the Federal Energy Regulatory Commission has changed the way utilities buy, transport, and sell natural gas. Known as FERC Order No. 636, this new ruling deregulates the sale of natural gas and makes gas procurement the responsibility of utilities. The change eliminates the "middle man," which should help lower purchased gas costs and allow LILCO to take advantage of new business opportunities. As a result we have sold gas outside our service area in markets from Mississippi to Connecticut. In another new venture, LILCO will act as fuel manager for a cogeneration facility at the Brooklyn Navy Yard. Under this contract, the company will broker a portion of its gas transportation capacity.


LILCO
SERVICE

◄ Meet Call Section Manager Mary Martin. She's an important part of LILCO's new Customer Assistance Center. Working with the center's more than 240 customer representatives, Mary is helping to improve the quality of LILCO's 24-hour-a-day call handling capability through better training and supervisory support. Also at the center are technical experts in conservation, electric, gas, and consumer services to provide immediate response to a wide range of customer inquiries.

Serving

LILCO is committed to providing unparalleled service to its customers. It is the guiding principle for every area of the company's operations from customer relations to electric and gas service. ► In fulfilling this commitment, LILCO employees have been faced with the challenge of responding faster and more accurately to requests for service, information, and assistance while employing cost-containment strategies. With improved set-ups like LILCO's new Customer Assistance Center, employees are finding innovative ways to provide better service by consolidating and streamlining resources.

LILCO responds to more than 800,000 gas and electric service requests annually. To respond faster and more accurately to these requests, ► the company developed a mobile communications system called the Computer-Assisted Radio Dispatch System, or CARDS. This new technology enables field workers like Gas Customer Service Specialist Jim Buttacavoli to work more efficiently with bett deployment of repair crews and provide automatic feedback on the status of a job. The new system also allows customers to schedule routine repair work at their convenience — another example of how LILCO is putting new technology to work for the people we serve.

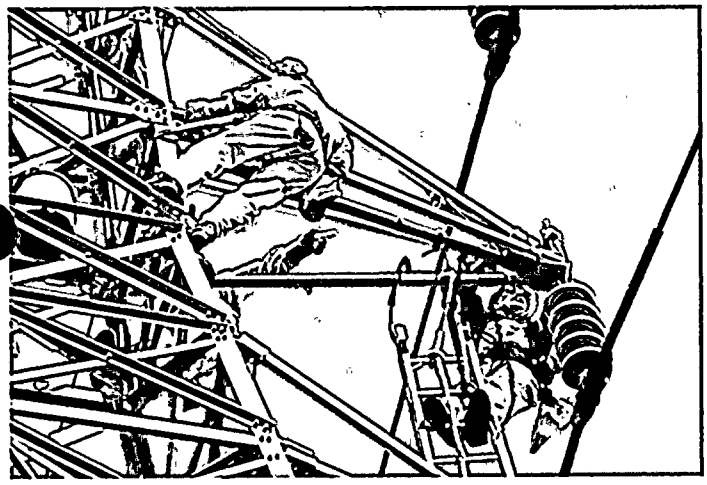
Adapting

From the company's reorganization to its new call-handling capabilities, technological innovation is providing the backbone to support LILCO's service initiatives. In reviewing every area of company operations, employees are searching for ways to apply new technologies to improve the efficiency, speed, and responsiveness of customer service. ► Applications such as the use of military technology to improve power plant operations and marine research to protect heating equipment exemplify how greater efficiency can be combined with improved service — just one of the ways LILCO continues to lower costs for customers.


LILCO
SERVICE

◄ On his own time, LILCO lineman Phil Batishko invented a tool to help in an expensive repair job reconstructing 82 of the company's transmission towers. The tool, a hydraulic jack mounted on an adjustable pole, supports heavy wire and relieves pressure on support arms while repairs are completed. Phil's innovative device helped make the work easier and faster, saving time and money during the 3½ month project.

Improving



To find out how to do a job better, just ask someone who does it. That's LILCO's philosophy — to turn employee ideas into action and savings for the company and its customers. With programs like the Employee Suggestion System, Q-Teams, and Service First, LILCO gives all employees a voice in how to improve efficiency and service. Their suggestions have saved the company and its customers millions of dollars. ► LILCO's most valuable asset will always be its dedicated and experienced employees. By listening carefully to their ideas, the company can provide better services at lower cost.

Financial Review

Overview

Nearly five years have passed since the effective date of the 1989 Settlement, discussed in Note 2 of Notes to Financial Statements, which resolved the controversy surrounding the Shoreham Nuclear Power Station (Shoreham). Over this period of time, the Company has focused on managing costs and improving operating efficiencies. This, coupled with six electric rate increases, lower than anticipated fuel and financing costs and significantly lower production expenses has helped to improve the Company's financial health. This also enabled the Company to file with the Public Service Commission of the State of New York (PSC) on December 31, 1993 an electric rate plan requesting that base rates be frozen for a two-year period beginning December 1, 1994.

The Company's electric rate plan to freeze base rates is designed to moderate the rate increases that were originally contemplated in the 1989 Settlement. The two-year base rate freeze will help better position the Company to respond to the current environment in the utility industry and to assist in Long Island's economic recovery.

Other significant events during 1993 included:

- Approval, by the PSC, of the third annual electric rate increase of 4.0% effective December 1, 1993, under the three-year electric rate plan authorized in 1991.
- For the first time since the 1989 Settlement became effective, revenues provided under the Rate Moderation Agreement exceeded revenues that would have been provided under conventional ratemaking, resulting in the decline of the Rate Moderation Component balance and an improvement in the Company's cash flow position.
- An increase in the Company's common stock quarterly dividend from 43½ cents per share to 44½ cents per share, representing the fourth consecutive year of dividend increases.

  Earnings for common stock in 1993 were $2.15 per common share compared to $2.14 per common share in 1992.
- The approval by the PSC of a three-year gas rate plan providing annual rate increases of 4.7%, 3.8% and 2.8%, for the rate years beginning December 1, 1993, 1994, and 1995, respectively. This follows an increase in gas rates of 7.1% that was effective December 1, 1992.
- The addition of over 9,000 new gas space heating customers, resulting from the Company's gas expansion program.
- The refinancing of a significant amount of the Company's higher-cost securities as a result of very favorable long-term interest rates.

  Refinancing of approximately $983 million of higher-cost securities significantly lowered the Company's cost of debt and preferred stock. These 1993 refinancings will result in more than $18 million in annual cash savings through lower interest expense and preferred stock dividends.

  Since the 1989 Settlement became effective, the Company's aggressive refinancing program has resulted in annual cash savings of approximately $88 million.

Liquidity and Capital Resources

Cash and Revolving Credit

At December 31, 1993, the Company's cash and cash equivalents amounted to approximately $249 million, compared to $309 million at December 31, 1992. In addition, the Company has approximately $276 million available through October 1, 1994, provided by its 1989 Revolving Credit Agreement (1989 RCA). At December 31, 1993, no amounts were outstanding under the 1989 RCA. For a further discussion of the 1989 RCA, see Note 7 of Notes to Financial Statements.

Capital Requirements and Capital Provided

During 1993, the Company continued its aggressive refinancing of higher-cost debt and preferred stock, taking advantage of declining interest rates. In 1993, the Company redeemed $568 million of higher-cost securities through the issuance of approximately $382 million of debentures and $204 million of preferred stock. The Company also issued $420 million of debentures to redeem $415 million of maturing debt.

In addition to these refinancings, the Company issued $200 million of debentures and $100 million of tax-exempt securities and used the proceeds to reimburse the Company's treasury for previously incurred capital expenditures. In November 1993, the Company satisfied the maturity of $175 million of debentures with cash on hand.

For a further discussion on the Company's capital stock and long-term debt, see Notes 6 and 7 of Notes to Financial Statements.

The Company expects that it will seek external financing of approximately $1.1 billion solely for the purpose of refunding maturing debt in the years 1994, 1995 and 1996 as follows:

	(In millions of dollars)		
	1994	1995	1996
First Mortgage Bonds	$ 25	$ 25	$ 40
General and Refunding Bonds	—	—	415
Debentures	575	—	—
	$600	$ 25	$455

The Company is planning, subject to market conditions, to fund a portion of these mandatory redemptions with the issuance of common equity in order to improve its debt-to-equity ratio.

Capital requirements and capital provided for 1993 and 1992 were as follows:

	(In millions of dollars)	
	1993	1992
Capital Requirements		
Construction		
Electric	$ 136	$ 137
Gas	125	104
Common	41	27
Total Construction	302	268
Refundings and Dividends		
Long-term debt	960	1,344
Preferred stock	206	389
Preferred stock dividends	57	70
Common stock dividends	196	191
Redemption costs	15	159
Total Refundings and Dividends	1,434	2,153
Shoreham post settlement costs	207	228
Total Capital Requirements	$1,943	$2,649
Capital Provided		
Decrease (increase) in cash	$ 61	$ (11)
Long-term debt	1,090	1,660
Preferred stock	202	411
Financing costs	(2)	(7)
Other financing activities	10	6
Internal cash generation from operations	582	590
Total Capital Provided	$1,943	$2,649

For further information, see the Statement of Cash Flows.

For 1994 total capital requirements (excluding common stock dividends) are estimated at $1.1 billion, of which mandatory redemptions are $600 million, construction requirements are $327 million, preferred stock sinking fund requirements are $5 million, preferred stock dividends are $53 million and Shoreham post settlement costs are $158 million.

During 1994, the Company expects to access the capital markets only for funds required to satisfy maturing securities or to refund outstanding securities to reduce financing costs. It is anticipated that the internal funds generated from operations will be sufficient to satisfy all other capital requirements, including both common and preferred stock dividends.

Capitalization

The Company's capitalization, including current maturities of long-term debt and current redemption requirements of preferred stock, at December 31, 1993, was approximately $8.4 billion, as compared to $8.2 billion at December 31, 1992. This increase in capitalization of approximately $185 million principally reflects an increase in long-term debt and preferred stock associated with the Company's financing activities in 1993 and an increase in common shareowners' equity comprising 1993 net income of approximately $296 million reduced by common and preferred stock dividends of approximately $253 million.

At December 31, 1993 and 1992, the components of the Company's capitalization ratios were as follows:

	1993	1992
Long-term debt	65.0%	64.7%
Preferred stock	8.5	8.8
Common shareowners' equity	26.5	26.5
	100.0%	100.0%

The Company's debt-to-equity ratio reflects two substantial charges to common shareowners' equity made in 1988 and 1989. In 1988, the Company was required to write-down net assets of approximately $1.3 billion, net of tax effects, relating to its investments in Shoreham and Nine Mile Point Nuclear Power Station, Unit 2 (NMP2). In 1989, the Company incurred a loss for common stock of approximately $175 million, reflecting the effects of the 1989 Settlement and the Class Settlement, discussed in Notes 2 and 4 of Notes to Financial Statements. The Company is committed to improving its debt-to-equity ratio through growth in retained earnings, debt reduction through improved cash flows, and the issuance of common equity.

Rate Matters

Electric

In conjunction with the 1989 Settlement, the PSC authorized 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). The Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides for the full recovery of the FRA. The RMA, by its terms, specifies that the FRA was created to provide the Company adequate financial indicia for the period 1989 through 1999 and to restore the Company's debt securities to investment grade levels as determined by independent rating agencies.

The BFC, 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.

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. This revenue difference, together with a carrying charge equal to the allowed rate of return on rate base, has been deferred. The RMC has provided the Company with a substantial amount of non-cash earnings since the effective date of the 1989 Settlement through December 31, 1992, because the revenues provided under the RMA were less than the revenues required under conventional ratemaking. During 1993, however, as 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 consistent with the objectives of the RMA. In response to the Company's rate filing in December 1990, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) in November 1991, which provided for annual electric rate increases of 4.15%, 4.1% and 4.0% effective December 1, 1991, 1992 and 1993, respectively. Effective December 1, 1993, the Company began receiving the third of these three annual electric rate increases. The LRPP provides 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 mitigates 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 will receive for each of the three rate years under the LRPP. Another component of 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 its performance within certain incentive and/or penalty programs. These programs consist of a customer service performance plan, a demand side management 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. For the rate years ended November 30, 1993 and 1992, the Company earned approximately $9.2 million and $4.3 million, net of tax effects, respectively, based upon its performance within these programs. The LRPP contains a mechanism whereby earnings in excess of the allowed rate of return on common equity (11.6%), excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners. For the rate years ended November 30, 1993 and 1992, the Company earned approximately $8.9 million and $21.4 million, net of tax effects, respectively, in excess of its allowed rate of return on common equity which was shared equally between ratepayers and shareowners.

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 continuing the restoration of the Company's financial health. The filing provides for zero percentage base rate increases in years one and two of the plan and a rate increase of 4.3% in the third year. Although base electric rates would be frozen during the first two years of the plan, annual rate increases of approximately 1% to 2% are expected to result in these years from the operation of the Company's fuel cost adjustment (FCA) clause. The FCA captures, among other amounts, any increases in the cost of fuel above the level recovered in base rates and, under a continuation of the rate mechanisms provided by the LRPP, any amounts to be recovered or refunded to ratepayers in excess of $15 million which result from the reconciliation of revenue, certain expenses and earned performance incentive components. The electric rate plan requests an allowed rate of return on equity of 11.0%. The Company's rate filing reflects four underlying objectives: (i) to limit the balance of the RMC

ring the three-year period to no more than its 1992 peak balance of $652 million; (ii) to recover the RMC within no more than thirteen years of its 1989 inception; (iii) to minimize the final three rate increases that will follow the two-year rate freeze period; and (iv) to continue the Company's gradual return to financial health. The Company's electric rate plan is subject to approval by the PSC.

The Company's current 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 demand side management (DSM), operations, maintenance and capital expenditures, the Company has determined that the overall objectives of the RMA can be met under the multi-year plan described above. As a result of lower than originally anticipated inflation rates, interest costs, property taxes, fuel costs and the return on common equity allowed by the PSC, the RMC, which originally had been anticipated to peak at $1.2 billion in 1994, has already peaked at $652 million in 1992. With the exception of an increase in the 1995-1996 period, which is not now projected to cause the RMC to increase above its $652 million peak, the RMC is expected to decline until it is fully amortized.

Under this 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 rate plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years.

For a further discussion of the 1989 Settlement and Rate Matters, see Notes 2 and 3 of Notes to Financial Statements.

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 the rate years beginning December 1, 1993, 1994 and 1995, annual gas rate increases of 4.7%, 3.8% and 2.8%, respectively. In the determination of the revenue requirements for the first year of the gas rate settlement an allowed rate of return on equity of 10.1% was used. The gas rate decision also provides for earnings in excess of a 10.6% return on 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. The allowed rate of return for the rate year that began December 1, 1992 was 11.0 %.

Electric Competition

Non-Utility Generators (NUGs)

The development of the NUG industry has been encouraged by federal and state legislation. There are two ways that NUGs may negatively impact the Company: first, NUGs may locate on a customer's site, providing part or all of that customer's electric energy requirements. The Company estimates that in 1993 sales lost to such on-site NUGs totalled 234 gigawatt-hours (Gwh) in sales or approximately $20 million in revenues, net of fuel. This represents only 1.0% of the Company's 1993 net revenues. Second, in accordance with the Public Utility Regulatory Policy Act of 1978 (PURPA), the Company is required to purchase all the power offered by NUGs that are Qualified Facilities (QF). QFs have the choice of pricing these sales at either (i) PSC published estimates of the Company's long run avoided costs (LRAC) or (ii) the Company's tariff rates. Additionally, until repeal in 1992, New York State law set a minimum price of six cents per kilowatt-hour (Kwh) for 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 the PSC's updates which resulted in lower LRAC estimates, has significantly reduced the economic advantage to entrepreneurs seeking to compete with the Company.

As of December 31, 1993, 39 QFs were on line and selling approximately 200 megawatts (MW) of power to the Company. The Company estimates that in 1993, the purchases federal and state law required it to make from QFs cost the Company $47 million more than it would have cost to generate this power itself.

With the exception of approximately 40 MW of power to be produced at the Stony Brook campus of the State University of New York beginning in early 1995, the Company does not expect any new major NUGs to be built on Long Island in the foreseeable future.

Retail Competition

For over a decade, the Company has voluntarily provided wheeling of New York Power Authority (NYPA) power for economic development. As a result, NYPA power has displaced approximately 400 Gwh of energy sales. The net revenue loss associated with this amount of sales is approximately $27 million or 1.3% of the Company's 1993 net revenues. The potential loss of additional load is limited by conditions in the Company's current transmission agreements with NYPA.

Competition for customer loads also comes from other electric utilities (including those in Connecticut, New York, and New Jersey) which seek to entice commercial and industrial customers to relocate within their service territories by offering reduced rates and other incentives.

In order to retain existing and attract new commercial and industrial customers, the Company offers an Economic Development Rate which provides rate abatement to new or existing customers that qualify under the program approved by the PSC.

Neither federal nor New York State law mandates retail wheeling. The Staff of the PSC has recently recommended that the PSC examine the issues attending retail wheeling.

Conservation and Supply

The Company's 1993 Electric Conservation and Load Management Plan called for a cumulative 194 MW reduction in coincident peak demand by December 31, 1993 and a cumulative annualized energy savings of 578 Gwh, at a cost of $33.5 million. The Company has met these targets. These reductions were achieved through several different programs including customer education/information, rebate, audit and direct installation which targeted a number of energy efficient technologies.

In the fourth quarter of 1993, a modified DSM Plan was filed with the PSC to support the objectives of the Company's December 31, 1993 electric rate plan filing. Under this modified plan a greater emphasis will be placed on the educational aspect of the Company's conservation efforts in lieu of the conventional reliance on rebates. This will help to shift the responsibility for adopting and implementing energy efficient practices away from the utility and to the customer.

The Company's current electric load forecasts indicate that, with continued implementation of its conservation and load management programs and with the availability of electricity provided by QFs located within the Company's service territory, the Company's existing generating facilities, its portion of nuclear energy generated at NMP2 and power purchased from other electric systems are adequate to meet the energy demands on Long Island beyond the end of the century.

Investment Rating

The Company's securities are rated by Moody's Investors Service, Inc. (Moody's), Standard and Poor's Corporation (S&P), Fitch Investors Service, Inc. (Fitch) and Duff and Phelps (D&P).

During the period 1989 through 1992, the rating agencies significantly upgraded their ratings of the Company's securities. In 1993, both Moody's and Fitch reaffirmed their assigned ratings on the Company's securities. S&P however, lowered its ratings on the Company's First Mortgage Bonds and G&R Bonds one level to minimum investment grade and lowered its ratings on the Company's Debentures and Preferred Stock to one level below minimum investment grade. D&P lowered its ratings on the Company's debentures and preferred stock one level.

S&P's actions reflect its concerns regarding the utility industry's challenges relating to intensified competitive pressures, sluggish demand expectations, slow earnings growth prospects, high common dividend payouts, environmental cost pressures and nuclear operating and decommissioning costs.

Clean Air Act

In late 1990, significant amendments to the federal Clean Air Act were adopted. As a result, the Company expects that it will have to expend $4.3 million in 1994 to meet continuous emission monitoring requirements and $3.5 million in 1994 and $2.0 million in 1995 to meet Phase I nitrogen oxide (NOx) reduction requirements. In addition, subject to regulations that have not yet been issued, the Company estimates that it may be required to expend as much as $125 million by May 1999 to meet Phase II NOx reduction requirements and approximately $50 million by 2000 to meet requirements for the control of hazardous air pollutants from power plants. The Company believes that all such costs would be recoverable in rates.

Results of Operations

Earnings

Summary results of earnings for the years 1993, 1992 and 1991 were as follows:

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

	1993	1992	1991
Net Income	$ 296	$ 302	$ 305
Preferred Stock Dividend Requirements	56	64	66
Earnings for Common Stock	$ 240	$ 238	$ 239
Average Shares Outstanding	112.1	111.4	111.3
Earnings per Common Share	$ 2.15	$ 2.14	$ 2.15
AFC & RMC (Deducted) Included in Net Income	$ (25)	$ 60	$ 183
AFC & RMC – % of Net Income	(8)%	20%	60%

For all periods, net income, earnings for common stock and earnings per common share include a non-cash allowance for funds used during construction (AFC) and the effects of the RMC.

Overall earnings remained stable in 1993 while the Company's improved cash flow continued, consistent with the 1989 settlement. 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 the short-term investments and regulatory adjustments. The lower level of earnings in the electric business was offset by a significant increase in the gas business earnings. The Company saw continued expansion in the gas business in 1993.

Revenues

Total revenues in 1993, including revenues from recovery of fuel costs, were $2.9 billion, representing an increase of $259 million or 9.9% over 1992 revenues. Total revenues for the Company's electric and gas operations for the years 1993, 1992 and 1991 were as follows:

(In millions of dollars)

	1993	1992	1991
Electric	$2,352	$2,195	$2,197
Gas	529	427	351
Total Revenues	$2,881	$2,622	$2,548

Electric Revenues

In 1993, electric revenues increased $157 million when compared to 1992. Revenues in 1992 had decreased $2 million compared with 1991. The changes in the level of revenues when compared to the prior year resulted from the following factors:

(In millions of dollars)

	'93/'92	'92/'91
Rate Increases	$ 75	$ 72
Sales Volumes	60	(61)
Fuel Cost Recoveries	22	(13)
Total	$ 157	$ (2)

Rate Increases

The Company received electric rate increases of 4.0% effective December 1, 1993 and 4.1% effective December 1, 1992. These rate increases provided $75 million in additional revenues for 1993 when compared to 1992. A 4.15% rate increase effective December 1, 1991 provided $72 million in additional revenues for 1992 when compared to 1991.

Sales Volumes

The increase in revenue from sales volumes was primarily attributable to warmer weather experienced in the summer of 1993 when compared to the same period in 1992. The decrease in revenues from sales volumes for 1992 when compared to 1991 is also attributable to weather. The Company's current electric rate structure, discussed above under the heading "Rate Matters," provides for a revenue reconciliation mechanism which mitigates the impact on earnings of experiencing electric 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 Amortizations" of $43.5 million, $78.5 million and $0.4 million in 1993, 1992 and 1991, respectively. For a further discussion on the recoverability of these amounts see the discussion under the heading "Rate Matters."

Summary of electric kilowatt hour (Kwh) sales for the years 1993, 1992 and 1991 were as follows:

(In millions of Kwh)

	1993	1992	1991
Residential	7,118	6,788	7,023
Commercial/Industrial	8,257	8,181	8,322
Other	449	471	469
System Sales	15,824	15,440	15,814
Power Pool Sales	304	227	598
Total Sales	16,128	15,667	16,412

The increase in residential and commercial/industrial sales in 1993 was largely due to the warmer weather experienced during the summer months. Residential sales, representing 45% of system sales, were up by 4.9% when compared with 1992, while commercial/industrial sales, which accounted for 52% of system sales, increased by 0.9%. Power pool sales fluctuate with relative costs and power pool system availabilities.

The average number of electric customers served in 1993 and 1992 was approximately 1,013,000 and 1,009,000, respectively. The customer increase in 1993 is similar to the increase experienced in 1992 when compared to 1991.

Fuel Cost Recoveries
Total electric fuel cost recoveries for 1993 were up $22 million compared with 1992, primarily as a result of higher sales volumes, partially offset by a decrease in the average cost of fuel. In 1992, fuel cost recoveries decreased by $13 million compared with 1991, principally due to lower sales volumes, partially offset by an increase in the average cost of fuel.

Gas Revenues

In 1993, gas revenues increased by $102 million, or 23.8%, when compared to 1992. Revenues in 1992 increased by $76 million, or 21.7%, when compared to 1991. The changes in the level of revenues when compared to the prior year resulted from the following factors:

(In millions of dollars)

	'93/'92	'92/'91
Rate Increases	$ 35	$ 17
Sales Volumes	34	50
Fuel Cost Recoveries	33	9
Total	$102	$ 76

Rate Increases
The Company received a gas rate increase of 4.7%, effective December 31, 1993, but was permitted by the PSC to recognize additional revenues of $4.6 million in 1993, as if the rate increase had been effective on December 1, 1993. The Company had also received rate increases of 7.1%, effective December 1, 1992, and 4.1%, effective December 1, 1991. The effects of these rate increases was to increase revenues by $35 million in 1993 when compared with 1992, and by $17 million in 1992 when compared with 1991.

Sales Volumes
The increase in 1993 revenues due to sales volumes was primarily due to customer additions and conversions resulting from the Company's gas expansion program. The Company added over 9,000 new gas space heating customers to its system in 1993. In 1992, the Company added approximately 10,000 new gas space heating customers.

Summary of gas decatherm (dth) sales for the years 1993, 1992 and 1991 were as follows:

(In thousands of dth)

	1993	1992	1991
Space Heating	51,557	48,751	41,323
Non-Space Heating	7,626	7,541	7,366
Total Firm	59,183	56,292	48,689
Interruptible	5,920	5,090	4,538
Total System	65,103	61,382	53,227
Off-System Sales	2,894	—	—
Total Sales	67,997	61,382	53,227

Fuel Cost Recoveries
Recoveries of gas fuel expenses in 1993 revenues increased by $33 million compared with 1992, primarily due to higher sales volumes. In 1992, fuel recovery revenues had increased by $9 million, primarily due to higher average gas prices.

Fuels and Purchased Power

Expenses for fuels and purchased power increased by $86 million in 1993 compared with 1992, and decreased by $27 million in 1992 compared with 1991.

Summary of fuel and purchased power expenses for the years 1993, 1992 and 1991 were as follows:

(In millions of dollars)

	1993	1992	1991
Fuels for Electric Operations			
Oil	$ 180	$ 190	$ 301
Gas	93	79	66
Nuclear	13	11	13
Purchased Power	293	280	214
Total	579	560	594
Gas Fuels	249	182	175
Total	$ 828	$ 742	$ 769

The Company has significantly reduced the amount of oil it would otherwise have used to generate electricity by burning gas, purchasing power and utilizing nuclear generation from NMP2.

Summary of electric fuel and purchased power mix for the years 1993, 1992 and 1991 were as follows:

(Percent of system energy requirements)

	1993	1992	1991
Oil	33%	37%	50%
Gas	19	19	18
Nuclear	7	6	7
Purchased Power	41	38	25
Total	100%	100%	100%

Operations and Maintenance Expenses

Total operations and maintenance expenses, excluding fuel and purchased power, for 1993, 1992 and 1991 were $522 million, $498 million and $523 million, respectively. The $24 million, or 4.8%, increase in 1993 when compared to 1992 was primarily due to the recognition of previously deferred storm costs, the recording of higher accruals for uncollectible accounts and higher transmission and distribution costs for both the electric and gas businesses. The $25 million, or 4.8%, decrease in 1992 compared to 1991 was primarily attributable to lower electric operations expenses.

Interest Expense

Interest expense for 1993, 1992 and 1991 was $534 million, $513 million and $524 million, respectively. 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 30-year fixed rate. Also contributing to the increase, was the issuance in November 1992 of 30-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 interest rates. Partially offsetting this increase in interest expense were the effects of the Company's aggressive refinancing of higher-cost debt in 1993. The decrease in 1992 when compared to 1991 is due to significantly lower interest rates on the Company's outstanding debt, primarily resulting from the Company's aggressive refinancing efforts in the latter part of 1991 and during 1992.

Rate Moderation Component

In 1993, the Company recorded non-cash charges to income of approximately $49 million reflecting the amortization of the RMC offset by related carrying charges. In 1992 and 1991, the Company recorded non-cash credits to income of approximately $73 million and $269 million, respectively, representing the accretion of the RMC and related carrying charges. For a discussion of the RMC and RMA, see Notes 2 and 3 of Notes to Financial Statements.

Base Financial Component

For each of the years 1993, 1992 and 1991, the Company recorded non-cash charges to income of approximately $101 million, reflecting the continuing amortization of the BFC, which is afforded rate base treatment under the RMA. For a further discussion of the BFC and 1989 Settlement, see Notes 1 and 2 of Notes to Financial Statements.

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. SFAS No. 106 requires the Company to recognize the expected cost of providing postretirement benefits when employee services are rendered rather than on a pay-as-you-go method. The Company recorded an accumulated postretirement benefit obligation and corresponding regulatory asset of approximately $376 million which represents the transition obligation at January 1, 1993. As a result of adopting SFAS No. 106, the Company's annual 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. This additional non-cash postretirement benefit cost has been accounted for as a regulatory asset. The PSC has permitted recovery of these regulatory assets through rates. The adoption of SFAS No. 106 had no impact on net income for the year ended December 31, 1993. For a further discussion of SFAS No. 106, see Note 8 of Notes to Financial Statements.

Effective January 1, 1993 the Company adopted SFAS No. 109, Accounting for Income Taxes. As permitted under SFAS No. 109, the Company has elected not to restate the financial statements of prior years. The adoption of SFAS No. 109 is in compliance with the PSC's Statement of Interim Policy on Accounting and Ratemaking issued in January 1993. This statement asserts that the adoption and ongoing implementation of SFAS No. 109 on an interim basis will be done in such a manner that all its provisions shall be complied with on a revenue neutral basis. As of January 1, 1993, the cumulative adjustment to the deferred tax liability and the corresponding regulatory asset is approximately $1.6 billion. The $800 million increase from the amount reported in interim financial statements results from the Company's further analysis of deferred taxes to recognize SFAS No. 109 requirements to present tax assets and liabilities gross. SFAS No. 109 requires, among other matters, recognition of the amount of current and deferred taxes payable or refundable at the date of the financial statements as a result of all events that have been recognized in the financial statements and adjustment of deferred income taxes for an enacted change in tax laws. For regulated enterprises, SFAS No. 109 prohibits net of tax accounting and reporting and requires recognition of a deferred tax liability for the tax benefits which are flowed through to its customers. A regulatory asset or liability will be recognized relating to such items if it is probable that the future increase or decrease in taxes payable thereon shall be recovered from or returned to customers through future rates. For a further discussion of SFAS No. 109, see Notes 1 and 10 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 9 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.

Financial Statements

Balance Sheet

(In thousands of dollars)

Assets At December 31	1993	1992
Utility Plant		
Electric	$ 3,544,569	$ 3,429,803
Gas	860,899	760,635
Common	201,418	172,703
Construction work in progress	176,504	161,663
Nuclear fuel in process and in reactor	16,533	19,216
	4,799,923	4,544,020
Less — Accumulated depreciation and amortization	1,452,366	1,382,872
Total Net Utility Plant	3,347,557	3,161,148
Regulatory Assets		
Base financial component (less accumulated amortization of $454,369 and $353,398)	3,584,461	3,685,432
Rate moderation component	609,827	651,657
Shoreham post settlement costs	777,103	586,045
Shoreham nuclear fuel	75,497	77,629
Postretirement benefits other than pensions	402,921	—
Regulatory tax asset	1,848,998	—
Other	311,832	220,380
Total Regulatory Assets	7,610,639	5,221,143
Nonutility Property and Other Investments	23,029	20,730
Current Assets		
Cash and cash equivalents	248,532	309,485
Special deposits	23,439	23,683
Customer accounts receivable (less allowance for doubtful accounts of $23,889 and $24,375)	249,074	208,049
Other accounts receivable	12,199	6,937
Accrued unbilled revenues	170,042	143,172
Materials and supplies at average cost	68,882	86,482
Fuel oil at average cost	35,857	51,702
Gas in storage at average cost	75,182	47,002
Prepayments and other current assets	41,652	40,402
Total Current Assets	924,859	916,914
Deferred Charges		
Unamortized cost of issuing securities	350,239	380,267
Accumulated deferred income taxes	1,157,009	1,027,733
Other	42,705	36,524
Total Deferred Charges	1,549,953	1,444,524
Total Assets	$ 13,456,037	$ 10,764,459

See Notes to Financial Statements.

(In thousands of dollars)

Capitalization and Liabilities At December 31	1993	1992
Capitalization		
Long-term debt	$ 4,887,733	$ 4,755,733
Unamortized premium and (discount) on debt	(17,393)	(14,731)
	4,870,340	4,741,002
Preferred stock — redemption required	649,150	557,900
Preferred stock — no redemption required	64,038	154,276
Total Preferred Stock	713,188	712,176
Common stock	561,662	558,002
Premium on capital stock	1,010,283	998,089
Capital stock expense	(50,427)	(39,304)
Retained earnings	711,432	667,988
Total Common Shareowners' Equity	2,232,950	2,184,775
Total Capitalization	7,816,478	7,637,953
Regulatory Liabilities		
Regulatory liability component	436,476	515,835
1989 Settlement credits	155,081	164,294
Regulatory tax liability	177,669	—
Other	138,612	100,470
Total Regulatory Liabilities	907,838	780,599
Current Liabilities		
Current maturities of long-term debt	600,000	590,000
Current redemption requirements of preferred stock	4,800	8,200
Accounts payable and accrued expenses	277,519	275,612
Accrued taxes (including federal income tax of $28,424 and $27,100)	52,656	67,525
Accrued interest	142,409	131,179
Dividends payable	54,542	53,966
Class Settlement	30,000	30,000
Customer deposits	27,046	24,815
Total Current Liabilities	1,188,972	1,181,297
Deferred Credits		
Class Settlement	164,942	167,066
Accumulated deferred income taxes	2,932,029	970,373
Other	12,622	9,871
Total Deferred Credits	3,109,593	1,147,310
Reserves for Claims and Damages	8,714	2,687
Pensions and Other Postretirement Benefits	424,442	14,613
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 13,456,037	$ 10,764,459

See Notes to Financial Statements.

Statement of Income

(In thousands of dollars except per share amounts)

For year ended December 31	1993	1992	1991
Revenues			
Electric	$ 2,352,109	$ 2,194,632	$ 2,196,568
Gas	528,886	427,207	351,161
Total Revenues	2,880,995	2,621,839	2,547,729
Expenses			
Operations — fuel and purchased power	827,591	741,784	768,702
Operations — other	387,808	372,209	375,267
Maintenance	133,852	125,736	147,492
Depreciation and amortization	122,471	119,137	118,955
Base financial component amortization	100,971	100,971	100,971
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortizations	(18,044)	(22,072)	10,375
Rate moderation component	88,667	(30,444)	(228,572)
Operating taxes	385,847	388,988	388,380
Federal income tax — current	6,324	530	515
Federal income tax — deferred and other	178,530	172,468	168,937
Total Expenses	2,125,444	1,880,734	1,762,449
Operating Income	755,551	741,105	785,280
Other Income and (Deductions)			
Allowance for other funds used during construction	2,473	4,725	2,202
Rate moderation component carrying charges	40,004	42,837	40,456
Other income and deductions, net	38,997	29,273	35,492
Class Settlement	(23,178)	(22,541)	(25,467)
Federal income tax (charge) — deferred and other	12,578	12,036	(12,201)
Total Other Income and (Deductions)	70,874	66,330	40,482
Income Before Interest Charges	826,425	807,435	825,762
Interest Charges and (Credits)			
Interest on long-term debt	466,538	450,621	472,974
Other interest	67,534	62,226	50,842
Allowance for borrowed funds used during construction	(4,210)	(7,386)	(3,592)
Total Interest Charges and (Credits)	529,862	505,461	520,224
Net Income	296,563	301,974	305,538
Preferred stock dividend requirements	56,108	63,954	66,394
Earnings for Common Stock	$ 240,455	$ 238,020	$ 239,144
Average Common Shares Outstanding (000)	112,057	111,439	111,348
Earnings per Common Share	$ 2.15	$ 2.14	$ 2.15
Dividends Declared per Common Share	$ 1.76	$ 1.72	$ 1.60

See Notes to Financial Statements.

Statement of Cash Flows

(In thousands of dollars)

For year ended December 31	1993	1992	1991
Operating Activities			
Net Income	$ 296,563	$ 301,974	$ 305,538
Adjustments to reconcile net income to net cash provided by operating activities			
Fuel moderation component	—	—	34,025
Provision for doubtful accounts	18,555	16,329	35,431
Depreciation and amortization	122,471	119,137	118,955
Base financial component amortization	100,971	100,971	100,971
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortizations	(18,044)	(22,072)	10,375
Rate moderation component	88,667	(30,444)	(228,572)
Rate moderation component carrying charges	(40,004)	(42,837)	(40,456)
Class Settlement	23,178	22,541	25,467
Amortization of cost of issuing and redeeming securities	52,063	41,204	27,456
Federal income tax — deferred and other	165,952	160,432	181,138
Allowance for other funds used during construction	(2,473)	(4,725)	(2,202)
Other	(2,197)	699	38,068
Changes in operating assets and liabilities			
Accounts receivable	(65,898)	(14,275)	(26,045)
Accrued unbilled revenues	(26,870)	(6,607)	2,352
Materials and supplies, fuel oil and gas in storage	5,265	(10,933)	28,217
Prepayments and other current assets	(1,250)	(5,548)	(1,035)
Accounts payable and accrued expenses	(8,800)	62,513	34,560
Accrued taxes	(14,869)	7,351	3,926
Other	(22,694)	(17,073)	(39,168)
Net Cash Provided by Operating Activities	582,013	590,064	520,428
Investing Activities			
Construction and nuclear fuel expenditures	(302,220)	(268,179)	(235,349)
Shoreham post settlement costs	(207,114)	(227,658)	(158,432)
Other	(934)	(1,484)	(3,923)
Net Cash Used in Investing Activities	(510,268)	(497,321)	(397,704)
Financing Activities			
Proceeds from issuance of long-term debt	1,089,770	1,659,928	1,532,247
Redemption of long-term debt	(960,000)	(1,344,283)	(1,129,000)
Proceeds from sale of preferred stock	201,709	411,373	63,130
Redemption of preferred stock	(205,600)	(389,428)	(70,638)
Preferred stock dividends paid	(56,727)	(69,923)	(65,838)
Common stock dividends paid	(195,794)	(190,477)	(172,584)
Cost of issuing and redeeming securities	(17,036)	(166,066)	(88,586)
Other	10,980	7,520	3,707
Net Cash (Used in) Provided by Financing Activities	(132,698)	(81,356)	72,438
Net (Decrease) Increase in Cash and Cash Equivalents	$ (60,953)	$ 11,387	$ 195,162
Cash and cash equivalents at beginning of year	$ 309,485	$ 298,098	$ 102,936
Net (decrease) increase in cash and cash equivalents	(60,953)	11,387	195,162
Cash and Cash Equivalents at End of Year	$ 248,532	$ 309,485	$ 298,098
Interest paid, before reduction for the allowance for borrowed funds used during construction	$ 469,978	$ 424,842	$ 477,240
Federal income tax paid	$ 6,000	$ 2,100	$ 1,650
Federal income tax refunded	$ 1,000	$ 1,566	$ 642

See Notes to Financial Statements.

Statement of Capitalization

At December 31	Shares Outstanding 1993	Shares Outstanding 1992	(In thousands of dollars) 1993	(In thousands of dollars) 1992
Common Shareowners' Equity				
Common stock, $5.00 par value	112,332,490	111,600,376	$ 561,662	$ 558,002
Premium on capital stock			1,010,283	998,089
Capital stock expense			(50,427)	(39,304)
Retained earnings			711,432	667,988
Total Common Shareowners' Equity			2,232,950	2,184,775
Preferred Stock — Redemption Required				
Par value $100 per share				
7.40% Series L	192,500	203,000	19,250	20,300
8.40% Series M	—	238,000	—	23,800
8.50% Series R	112,500	150,000	11,250	15,000
7.66% Series CC	570,000	570,000	57,000	57,000
Less — Sinking fund requirement			4,800	6,200
			82,700	109,900
Par value $25 per share				
$2.47 Series O	—	880,000	—	22,000
$2.35 Series Z	—	2,600,000	—	65,000
7.95% Series AA	14,520,000	14,520,000	363,000	363,000
$1.67 Series GG	880,000	—	22,000	—
$1.95 Series NN	1,554,000	—	38,850	—
7.05% Series QQ	3,464,000	—	86,600	—
6.875% Series UU	2,240,000	—	56,000	—
Less — Sinking fund requirement			—	2,000
			566,450	448,000
Total Preferred Stock — Redemption Required			649,150	557,900
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	20,375	22,757	2,038	2,276
8.12% Series J	—	250,000	—	25,000
8.30% Series K	—	300,000	—	30,000
			64,038	119,276
Par value $25 per share				
$2.43 Series P	—	1,400,000	—	35,000
Total Preferred Stock — No Redemption Required			64,038	154,276
Total Preferred Stock			713,188	712,176

Long-Term Debt	Maturity	Interest Rate	Series		
First Mortgage Bonds (excludes Pledged Bonds)					
	April 1, 1993	4.40%	M	—	40,000
	June 1, 1994	4 5/8%	N	25,000	25,000
	June 1, 1995	4.55%	O	25,000	25,000
	March 1, 1996	5 1/4%	P	40,000	40,000
	April 1, 1997	5 1/2%	Q	35,000	35,000
	September 1, 1999	8.20%	R	—	35,000
	April 1, 2001	7 1/4%	U	—	40,000
	December 1, 2001	7 1/2%	V	—	50,000
	September 1, 2002	7 5/8%	W	—	50,000
	December 1, 2003	8 1/8%	X	—	60,000
Total First Mortgage Bonds				125,000	400,000

(In thousands of dollars)

December 31	Maturity	Interest Rate	Series	1993	1992
General and Refunding Bonds					
	May 1, 1996	8 3/4%		415,000	415,000
	February 15, 1997	8 3/4%		250,000	250,000
	May 15, 1999	7.85%		56,000	56,000
	May 15, 2006	8.50%		75,000	75,000
	December 1, 2006	8 5/8%		—	50,000
	May 1, 2007	8 5/8%		—	85,000
	July 15, 2008	7.90%		80,000	80,000
	May 1, 2021	9 3/4%		415,000	415,000
	July 1, 2024	9 5/8%		375,000	375,000
Total General and Refunding Bonds				1,666,000	1,801,000
Debentures					
	April 1, 1993	11 3/8%		—	375,000
	November 15, 1993	11.70%		—	175,000
	June 15, 1994	10.25%		400,000	400,000
	November 15, 1994	11.75%		175,000	175,000
	June 15, 1999	10.875%		30,545	30,545
	July 15, 1999	7.30%		397,000	397,000
	January 15, 2000	7.30%		36,000	—
	July 15, 2001	6.25%		145,000	—
	March 15, 2003	7.05%		150,000	—
	March 1, 2004	7.00%		59,000	—
	June 1, 2005	7.125%		200,000	—
	March 1, 2007	7.50%		142,000	—
	June 15, 2019	11.375%		4,513	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	—
Total Debentures				2,880,058	2,428,058
Authority Financing Notes					
Pollution Control Revenue Bonds					
	December 1, 2006	7.5%	1976A	28,375	28,375
	December 1, 2009	7.8%	1979B	19,100	19,100
	October 1, 2012	8 1/4%	1982	17,200	17,200
	March 1, 2016	2.5%	1985A,B	150,000	150,000
Electric Facilities Revenue Bonds					
	September 1, 2019	7.15%	1989A,B	100,000	100,000
	June 1, 2020	7.15%	1990A	100,000	100,000
	December 1, 2020	7.15%	1991A	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	2.95%	1993 A	50,000	—
	November 1, 2023	2.85%	1993 B	50,000	—
Industrial Development Revenue Bonds					
	December 1, 2006	7.5%	1976A,B	2,000	2,000
Total Authority Financing Notes				816,675	716,675
Unamortized Premium and (Discount) on Debt				(17,393)	(14,731)
Total Long-Term Debt				5,470,340	5,331,002
Less — Current maturities				600,000	590,000
Total Long-Term Debt Less Current Maturities				4,870,340	4,741,002
Total Capitalization				$7,816,478	$7,637,953

See Notes to Financial Statements.

Statement of Retained Earnings

(In thousands of dollar

	1993	1992	1991
Balance at January 1	$ 667,988	$ 620,373	$ 560,405
Net income for the year	296,563	301,974	305,538
	964,551	922,347	865,943
Deductions			
Cash dividends declared on preferred stock	55,861	62,387	67,261
Cash dividends declared on common stock	197,236	191,693	178,169
Capital stock expense	22	279	140
Balance at December 31	$ 711,432	$ 667,988	$ 620,373

See Notes to Financial Statements.

Notes to Financial Statements

Note 1. Summary of Significant Accounting Policies

Regulation

The Company's accounting policies conform to generally accepted accounting principles (GAAP) 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).

Utility Plant

Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, overhead 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 9.73%, 9.98% and 10.74% for the years 1993, 1992 and 1991, 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%, 3.2% and 3.3% of respective average depreciable plant costs for the years 1993, 1992 and 1991. Depreciation for gas properties was equivalent to approximately 2.0%, 2.6% and 2.9% of respective average depreciable plant costs for the years 1993, 1992 and 1991.

Financial Resource Asset

GAAP authorizes recognition of the existence of a regulatory asset when it is probable that a regulator will permit full recovery of a previously incurred cost. Pursuant to the 1989 Settlement and in accordance with GAAP, 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 Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides for the full recovery of the FRA. For a further discussion of the 1989 Settlement and the FRA, see Note 2.

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 a discounted cash flow analyses which is 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 or new issues. 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 or new issues.

Revenues
The Company accrues electric and gas revenues for services rendered to customers but not billed at month-end.

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 Taxes
Effective January 1, 1993, the Company adopted the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes. As permitted under SFAS No. 109, the Company has elected not to restate the financial statements of prior years. The adoption of SFAS No. 109 is in compliance with the PSC's Statement of Interim Policy on Accounting and Ratemaking issued January 15, 1993. This statement asserts that the adoption and ongoing implementation of SFAS No. 109 on an interim basis will be done in such a manner that all its provisions shall be complied with on a revenue neutral basis. As of January 1, 1993, the cumulative adjustment to the deferred tax liability and the corresponding regulatory asset is approximately $1.6 billion. The $800 million increase from the amount reported in interim financial statements results from the Company's further analysis of deferred taxes to recognize SFAS No. 109 requirements to present tax assets and liabilities gross. SFAS No. 109 requires, among other matters, recognition of the amount of current and deferred taxes payable or refundable at the date of the financial statements as a result of all events that have been recognized in the financial statements and adjustment of deferred income taxes for an enacted change in tax laws. For regulated enterprises, SFAS No. 109 prohibits net of tax accounting and reporting and requires recognition of a deferred tax liability for the tax benefits which are flowed through to its customers. A regulatory asset or liability will be recognized relating to such items if it is probable that the future increase or decrease in taxes payable thereon shall be recovered from or returned to customers through future rates.

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.

Prior to the adoption of SFAS No. 109 the Company provided deferred federal income taxes with respect to certain items of income and expense that were reported in different years in the financial statements and the tax return.

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 net income before income taxes and taxable income in certain instances when approved by the PSC, as disclosed in Note 10. 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 worker's compensation claims, property damage, extraordinary storm costs and general liability claims, are partially self-insured. 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 between $5 million and $50 million. Storm losses which are outside of the above-mentioned range are self-insured by the Company. Reserves for these losses are based on, among other things, experience, risk of loss and the ratemaking practices of the PSC.

Reclassifications
To conform with an order of the FERC, dated March 31, 1993, the Company reclassified certain deferred items as regulatory assets and regulatory liabilities on its Balance Sheet. Regulatory assets and liabilities, as defined in this order, are assets and liabilities created through the ratemaking actions of regulatory agencies.

Certain other 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 (by its Governor) entered into the 1989 Settlement resolving certain issues relating to the Company and providing, among other matters, for the transfer of the Shoreham Nuclear Power Station (Shoreham) and its subsequent decommissioning. 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, LIPA is responsible for the decommissioning of Shoreham and has estimated that the decommissioning, in which Company employees are participating, will be completed in 1994. Based on the latest available information, LIPA has projected that the cost of decommissioning Shoreham will total approximately $164 million. This estimate excludes the costs associated with the disposal of Shoreham's fuel which is estimated to be $122 million. At December 31, 1993, the Company has funded approximately $140 million and $30 million of these costs, respectively. LIPA anticipates that the Nuclear Regulatory Commission (NRC) will terminate its license for Shoreham by the end of 1994.

Upon the effectiveness of the 1989 Settlement, in June of 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, discussed in Note 1.

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, 1993 and 1992, the unamortized balance of the BFC was approximately $3.6 billion and $3.7 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. 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 state gross receipts tax adjustments related to the FRA. The RMC has provided the Company with a substantial amount of non-cash earnings from the effective date of the 1989 Settlement through December 31, 1992.

At December 31, 1993 and 1992, the RMC balance was $610 million and $652 million, respectively. 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, had been deferred. Subsequent to December 31, 1992, the RMC balance has been decreasing as revenues resulting from the implementation of the rate moderation plan are greater than revenue requirements under conventional ratemaking. For a further discussion of the impact on the amortization of the RMC under the Company's current electric rate structure and the Company's proposed electric rate plan for the three-year period beginning December 1, 1994, see Note 3.

Under 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 from the effective date of the 1989 Settlement. The Company has reclassified the regulatory liability component which was previously reported as a reduction of the corresponding deferred tax asset arising from the abandonment loss deduction.

Shoreham post settlement costs (decommissioning, payments in lieu of property taxes and other costs as incurred) are being capitalized and amortized and recovered through rates over a forty-year period on a straight-line remaining life basis.

Upon the effectiveness of the 1989 Settlement, Shoreham nuclear fuel was reclassified to deferred charges included in the Regulatory Asset section of the Balance Sheet and is being amortized and recovered through rates over a forty-year period on a straight-line remaining life basis.

The 1989 Settlement credits on the Balance Sheet of approximately $155 million, net of amortization, reflect 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. The remaining portion is not currently being recognized for ratemaking purposes under the 1989 Settlement.

Note 3. Rate Matters

Electric

Pursuant to the 1989 Settlement, discussed in Note 2, the Company received electric rate increases 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 response to the Company's December 1990 rate filing, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) in November 1991, which provides that the Company receive, for each of the three rate years in the period beginning December 1, 1991, annual electric rate increases of 4.15%, 4.1% and 4.0%, respectively, 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 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. 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 reduces 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 over the three rate years 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 charges and demand side management (DSM) costs, the deferral and amortization of certain costs for enhanced reliability, 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 and, effective December 1, 1993, an electric transmission and distribution reliability plan. The incentives and/or penalties related to the customer service performance plan, the time-of-use program, the electric transmission and distribution reliability plan and the partial pass through fuel cost incentive plan 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 approximately 49 basis points or approximately $9.2 million, net of tax effects, and 23 basis points, or approximately $4.3 million, net of tax effects, for the rate years ended November 30, 1993 and 1992, respectively.

The deferred balances resulting from the net margin, property taxes, interest expense, 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 or recovered from the ratepayers through the FCA over a twelve-month period in the following rate year.

During 1993, the PSC authorized the Company recovery of $45.2 million of the total net deferrals for the rate year ended November 30, 1992. The first $15 million of the total net deferrals was recorded as an increase to the RMC, with the remaining $30.2 million being recovered from the ratepayers through the FCA through July 31, 1994. For the rate year ended November 30, 1993, the total net deferrals, to be recovered from the ratepayers, subject to PSC review, amounted to approximately $63 million of which $48 million will be recovered through the FCA, over a twelve-month period beginning December 1, 1994.

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 rate of return on common equity of 11.6% which, in accordance with the LRPP, was shared equally between ratepayers (by a reduction to the RMC) and shareowners. Prior to December 1, 1991, the RMA provided that earned returns on common equity in excess of targeted allowed rates of return, were to be applied to reduce the RMC or mitigate rates, as determined by the PSC, at the end of each rate year. For the rate year ended November 30, 1991, the Company earned $10.1 million, net of tax effects, in excess of its allowed rate of return, which was applied as a reduction to the RMC.

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 1993 and 1992, the Company applied a total of approximately $10.1 million and $22.5 million of various deferred ratepayer benefits to the RMC including the ratepayers portion of the excess earnings for the rate years ended November 30, 1993 and 1992, respectively.

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 continuing the restoration of the Company's financial health. The electric rate plan provides for zero percentage base rate increases before giving effect to the reductions required by the Class Settlement, discussed in Note 4, in years one and two of the plan and a base rate increase of 4.3% in the third year prior to giving effect to the reductions required by the Class Settlement. Although base electric rates would be frozen during the first two years of the plan, annual rate increases of approximately 1% to 2% are expected to result in these years from the operation of the Company's FCA. The FCA captures, among other amounts, any increases in the cost of fuel above the level recovered in base rates, and under the LRPP, any amounts to be recovered or refunded to ratepayers in excess of $15 million which result from the reconciliation of revenue, certain expenses and earned performance incentive components, discussed above. The electric rate plan requests an allowed rate of return on equity of 11.0%. The Company's two-year base rate freeze proposal 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 no more than thirteen years of its 1989 inception; (iii) to minimize the final three rate increases that will follow the two-year rate freeze period; and (iv) to continue the Company's gradual return to financial health. The Company's electric rate plan is subject to approval by the PSC.

The Company's current 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 multi-year plan described above. 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, has already peaked at $652 million in 1992. With the exception of an increase in 1995-1996, which is not now projected 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 rate plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years instead of ten years.

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. In the determination of the revenue requirements for the first year of the gas rate settlement an allowed rate of return on equity of 10.1% was used. The gas rate decision also provides for earnings in excess of a 10.6% return on 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. The allowed rate of return for the rate year that began December 1, 1992 was 11.0%.

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 (RICO 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 ratepayers with reductions, aggregating $390 million, that are to be reflected as adjustments to their monthly electric bills over a ten-year period which began on June 1, 1990.

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

June 1994	$30 million
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 such liability that result from the passage of time and from monthly reductions. The Company expects the Class Settlement liability will be fully satisfied by May 31, 2000.

As a result of the Class Settlement, the Company's electric rate increases on average will be approximately .2% to .3% per year lower than they would otherwise have been during the Class Settlement period.

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, 1993, the Company's net utility plant investment in NMP2 was $759 million, net of accumulated depreciation of $119 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 the 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.

Based upon a study performed by NMPC which reflects a change in the NRC minimum decommissioning funding requirement effective 1993, the Company's share of the decommissioning costs for NMP2 is estimated to be $80 million (in 1993 dollars) assuming that decommissioning will commence in 2027 (which will be $234 million in 2027 dollars). The Company's share of estimated decommissioning costs are being provided for in electric rates and are being charged to operations as depreciation expense. The amount of accumulated decommissioning costs collected from the Company's ratepayers through December 31, 1993 was $7.1 million. Amounts collected by the Company for the decommissioning of the contaminated portion of the NMP2 plant, which approximate 92% of total decommissioning costs, are held in an independent decommissioning trust fund. This fund complies with regulations issued by the NRC governing the funding of nuclear plant decommissioning costs. The Company's funding plan for its share of decommissioning costs will provide reasonable assurance that, at the time of termination of operation, adequate funds for the decommissioning of the Company's share of the contaminated portion of NMP2 plant will be available.

Note 6. Capital Stock

Preferred Stock

The Company has 7,000,000 authorized shares, cumulative preferred stock, par value $100 and 30,000,000 authorized shares, cumulative preferred stock, par value $25. 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, 1993 and 1992 amounted to $658,795,000 and $581,984,000, respectively, compared to their carrying amounts of $653,950,000 and $566,100,000, respectively.

At December 31, 1993, the Company had the option to redeem all outstanding preferred stock Series L, $100 par value, and Series R, $100 par value, at their optional redemption prices of $102.99 per share and $100.50 per share, respectively. No other preferred stock series subject to mandatory redemptions were redeemable at December 31, 1993.

The Company is required to redeem the following series of preferred stock through the operation of various sinking fund provisions: (i) on each July 31, 10,500 shares of the Series L at a price of $100 per share; (ii) on each December 15, 37,500 shares of the Series R at a price of $100 per share; (iii) on each March 1, commencing March 1, 1999, 77,700 shares of the Series NN at a price of $25 per share; and (iv) on each October 15, commencing October 15, 1999, 112,000 shares of the Series UU at a price of $25 per share. In addition, the Company will have the noncumulative option to double the number of shares to be redeemed pursuant to the sinking fund in any year for the preferred stock series mentioned above. The aggregate par value of preferred stock required to be redeemed by use of sinking funds in each of the years 1994 through 1996 is $4.8 million and in 1997 and 1998 is $1.1 million.

The Company is also required to redeem 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 CC on August 1, 2002; (ii) Series AA on June 1, 2000; (iii) Series GG on March 1, 1999; and (iv) Series QQ on May 1, 2001.

During 1992, the Company issued $363 million Preferred Stock, 7.95% Series AA and $57 million Preferred Stock, 7.66% Series CC, the proceeds of which were used to redeem $320 million Preferred Stock, $2.65 Series Y and $55 million Preferred Stock, 9.80% Series S, respectively, at their optional redemption prices.

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, 1993, the call prices were as follows:

5.00% Series B	$101.00
4.25% Series D	$102.00
4.35% Series E	$102.00
4.35% Series F	$102.00
5 1/8% Series H	$102.00
5 3/4% Series I – Convertible	$100.00

Preference Stock

None of the authorized 7,500,000 shares of nonparticipating preference stock, par value $1 per share, which ranks junior to preferred stock, are outstanding.

Common Stock

Of the 150,000,000 shares of authorized common stock at December 31, 1993, 1,789,842 shares were reserved for sale through the Company's Employee Stock Purchase Plan, 5,946,929 shares were committed to the Automatic Dividend Reinvestment Plan (ADRP) and 118,812 shares were reserved for conversion of the Series I Convertible Preferred Stock at a rate of $17.15 per share. In June 1992, the Company reinstated the ADRP which had been suspended since February 1984. 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.

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 G&R 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 $1.03 billion at December 31, 1993 and 1992. The annual First Mortgage depreciation fund and sinking fund requirements for 1993, due not later than June 30, 1994, are estimated at $216 million and $18 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 1993, due not later than June 30, 1994, is estimated at $24 million. The Company expects to satisfy this requirement with retired G&R Bonds.

1989 Revolving Credit Agreement

The Company has an estimated $276 million available to it through October 1, 1994, under its $300 million 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.

The Company is currently, with the approval of the NRC, dedicating $24 million of the 1989 RCA to cover estimated, not yet incurred, costs attributable to the decommissioning of Shoreham, discussed in Note 2. The amount of credit available to the Company under the 1989 RCA will increase as decommissioning costs are funded by the Company.

At December 31, 1993, 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 termination date of the 1989 RCA may be extended for one-year periods upon the acceptance by the lending banks of the Company's request delivered to the lending banks prior to April 1 in each year.

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 Pollution Control Revenue Bonds (PCRBs), Electric Facilities Revenue Bonds (EFRBs) and Industrial Development Revenue Bonds issued by NYSERDA. Certain of these bonds are subject to periodic tender at which time their interest rates are subject to redetermination.

The 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 $272 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 November 17, 1996 for the 1993 EFRBs and on March 16, 1996 for the 1985 PCRBs, at which time 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 and the 1985 PCRBs must be redeemed unless the Company purchases them in lieu of redemption and subsequently remarkets them.

Tender requirements of Authority Financing Notes at December 31, 1993 are as follows:

(In thousands of dollars)

Interest Rate	Series	Principal	
PCRBs			
8¼%	1982	$ 17,200	Tendered every three years, next tender October 1994.
2.5%	1985 A,B	$ 150,000	Tendered annually on March 1.
EFRBs			
2.95%	1993 A	$ 50,000	Tendered weekly.
2.85%	1993 B	$ 50,000	Tendered annually on November 1.

Fair Values of Long-Term Debt

The carrying amounts and fair values of the Company's long-term debt consisted of the following at December 31:

(In thousands of dollars)

	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 Long-Term Debt	$ 5,727,746	$ 5,487,733

	1992	
	Fair Value	Carrying Amount
First Mortgage Bonds	$ 397,971	$ 400,000
General and Refunding Bonds	1,891,842	1,801,000
Debentures	2,523,721	2,428,058
Authority Financing Notes	729,610	716,675
Total Long-Term Debt	$ 5,543,144	$ 5,345,733

Maturity Schedule

Total long-term debt maturing in the next five years is $600 million (1994), $25 million (1995), $455 million (1996), $286 million (1997) and $1 million (1998).

Note 8. Retirement Benefit Plans

Pension Plans

The Company maintains a primary defined benefit pension plan (Primary Plan) which covers substantially all employees, a supplemental plan (Supplemental Plan) which covers officers and certain key executives and a retirement plan which covers the Board of Directors (Directors' Plan).

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.

Effective January 1, 1992, the Plan was amended to update the benefit calculation, whereby 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 a certain percentage, determined by years of service at December 31, 1991. For service after January 1, 1992, pension benefits are equal to 2% of Plan compensation through age 49 and 2 1/2% thereafter. Employees are vested in the pension plan after five years of service with the Company.

The Primary Plan's funded status reflects changes in assumptions used in accounting due to changes in market conditions. The 1993 projected benefit obligation increased by approximately $31 million due to changes in the discount rate used, partially offset by a lower rate of future compensation increases.

The Primary Plan's funded status and amounts recognized on the Balance Sheet at December 31, 1993 and 1992 were as follows:

	(In thousands of dollars)	
	1993	1992
Actuarial present value of benefit obligation		
Vested benefits	$ 512,692	$ 453,201
Nonvested benefits	5,920	4,326
Accumulated benefit obligation	$ 518,612	$ 457,527
Plan assets at fair value	$ 598,600	$ 556,399
Actuarial present value of projected benefit obligation	597,128	536,818
Projected benefit obligation less than plan assets	1,472	19,581
Unrecognized January 1, net obligations	91,397	98,147
Unrecognized net gain	(97,029)	(128,218)
Net accrued pension cost	$ (4,160)	$ (10,490)

Periodic pension cost for 1993, 1992 and 1991 for the Primary Plan included the following components:

	(In thousands of dollars)		
	1993	1992	1991
Service cost – benefits earned during the period	$ 14,481	$ 13,661	$ 14,323
Interest cost on projected benefit obligation and service cost	41,865	39,574	33,698
Actual return on plan assets	(54,010)	(47,156)	(63,875)
Net amortization and deferral	10,025	12,849	33,569
Net periodic pension cost	$ 12,361	$ 18,928	$ 17,715

Assumptions used in accounting for the Primary Plan were:

	1993	1992	1991
Discount rate	7.25%	7.75%	7.75%
Rate of future compensation increases	5.0%	5.5%	5.5%
Long-term rate of return on assets	7.5%	7.5%	7.0%

The Primary Plan assets at fair value primarily 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 any deferred net gains or losses over a ten-year period rather than using the corridor approach method. The Company believes that by adopting this method of accounting for financial reporting purposes, a better matching of revenues and the Companay's pension cost will result from the implementation of the PSC order. For the year ended December 31, 1993, this change in the annual pension cost calculation reduced pension expense by approximately $4.6 million. The Company deferred a like amount of revenues to reflect the difference between pension expense in rates and pension expense under the PSC's order. In addition, the PSC authorized the Company to defer the difference between the pension rate allowance and annual pension contributions deposited into the pension fund. The Company is required to accrue, to the benefit of the ratepayer, a carrying charge on any such deferred balance.

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 retirement benefits, which is unfunded, totaled approximately $2,800,000, $685,000 and $675,000 which was recognized as an expense in 1993, 1992 and 1991, respectively.

Directors' Plan
The Directors' Plan, adopted in February 1990, 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 $150,000, $133,000 and $101,000 which was recognized as expense in 1993, 1992 and 1991, 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 on a pay-as-you-go method.

Effective January 1, 1993, the Company 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 annual 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 a final order which required that the effects of implementing SFAS No. 106 be phased into rates. The order required 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 fully reflected in rates within a five-year period with the accumulated postretirement obligation being recovered in rates over a twenty-year period.

Accumulated postretirement benefits obligation at December 31 were as follows:

	(In thousands of dollars)	
	1993	1992
Retirees	$ 152,800	$ 140,900
Fully eligible plan participants	63,800	78,500
Other active plan participants	137,200	156,200
Accumulated postretirement benefits obligation	353,800	375,600
Unrecognized net gain	49,237	—
Unrecognized transition obligation	—	(375,600)
Accrued postretirement benefit cost	$ 403,037	$ —

Periodic postretirement benefit cost for the years 1993 and 1992 were as follows:

	1993	1992
Service cost – benefits earned during the period	$ 12,980	$ —
Interest cost on projected benefits obligation and service cost	29,531	—
Periodic postretirement cost	$ 42,511	$ 13,400

Assumptions used in accounting for postretirement benefits were as follows:

	1993	1992
Discount rate	7.25%	7.75%
Rate of future compensation increases	5.0%	5.5%

The assumed health care cost trend rates used in measuring the accumulated postretirement benefit obligation at December 31, 1993 and 1992 were 9.5% and 15.0%, 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, 1993 and 1992 by approximately $46 million and $58 million, respectively, and the sum of the service and interest costs in 1993 by $8 million.

Postemployment Benefits
In November 1992, the FASB issued SFAS No. 112, Employers' Accounting for Postemployment Benefits, which establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement. The Company will be required to comply with the new rules beginning in 1994. The effect of adopting the new rules will not be material to the Company's financial position or results of operations. The Company believes it will be permitted to recover these costs through rates.

Note 9. Commitments and Contingencies

Commitments

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

The Company expects that it will have to expend $4.3 million in 1994 to meet continuous emission monitoring requirements and $3.5 million in 1994 and $2.0 million in 1995 to meet Phase I nitrogen oxide (NOx) reduction requirements. In addition, subject to details that are expected to appear in regulations that have not yet been issued, the Company estimates that it may be required to expend as much as $125 million by May 1999 to meet Phase II NOx reduction requirements and approximately $50 million by 2000 to meet requirements for the control of hazardous air pollutants from power plants. The Company believes that such cost would be recoverable in rates.

Contingencies

Litigation

On February 11, 1988, the Company began a lawsuit in Suffolk County Supreme Court against Suffolk County, seeking the recovery of approximately $54 million in damages for Suffolk County's breach of a contract to prepare an off site emergency response plan for Shoreham (Long Island Lighting Company v. County of Suffolk). In addition, the complaint alleges that, because of the delays that have resulted, the Company has been damaged in an additional amount of $706 million. On October 30, 1992, the court granted in part and denied in part Suffolk County's motion to amend its answer to assert additional defenses and counterclaims. Two proposed counterclaims were allowed seeking approximately $16 million in damages as well as $700 million in alleged punitive damages. The outcome of these counterclaims, if adverse, could have a material effect on the financial condition of the Company. The Company has argued that there is no basis for punitive damages and intends to vigorously prosecute its claim against Suffolk County and to defend against these counterclaims.

Environmental

The Company is subject to environmental laws and regulations of the United States Environmental Protection Agency (EPA) and other regulatory agencies. The Company is monitoring its activities and to date, has not identified any material environmental contingencies. The Company believes that costs related to such contingencies, if any, would be recoverable in rates.

Nuclear Plant Insurance

The Company has property damage insurance and third-party bodily injury and property liability insurance for its 18% share in NMP2 and for Shoreham. The premiums for this coverage are not material. The policies for this coverage provide for retroactive premium assessments under certain circumstances. Maximum retroactive premium assessments could be as much as approximately $4.7 million. 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.

Under certain circumstances, the Company may be assessed additional amounts in the event of a nuclear incident. Under agreements established pursuant to the Price Anderson Act, the Company could be assessed up to approximately $79.3 million per nuclear incident in any one year at any nuclear unit, but not in excess of approximately $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 $9.4 billion.

Note 10. Federal Income Taxes

As of December 31, 1993, 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)
Deferred Tax Assets	
Net operating loss carryforwards	$ 707,400
Litigation settlements	87,050
Shoreham property	38,535
Accelerated depreciation	20,612
Excess credits	35,362
Unutilized investment tax credits	67,215
Tax credit carryforwards	138,035
Other	62,800
Total Deferred Tax Assets	1,157,009
Deferred Tax Liabilities	
1989 Settlement	2,180,413
Accelerated depreciation	597,827
Call premiums	63,735
Rate case deferrals	43,957
Other	46,097
Total Deferred Tax Liabilities	2,932,029
Net Deferred Tax Liability	$ 1,775,020

The Company's net operating loss (NOL) carryforward for federal income tax purposes is estimated to be approximately $2 billion at December 31, 1993. The NOL will expire in the years 2003 through 2007. The amount of investment tax credit (ITC) carryforward is approximately $219 million. The ITC credits expire by the year 2002. In accordance with the Tax Reform Act of 1986 (TRA 86), ITC allowable as credits to tax returns for years after 1987 must be reduced by 35%. The amount of the reduction will not be allowed as a credit for any

er taxable year. 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 1984-1987 and 1988-1989, respectively. The Revenue Agents' Reports reflects 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 carryforward by approximately $96 million. The Company is protesting some of the adjustments and seeks 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.

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 net income before income taxes. The table below sets forth the reasons for such differences.

(In thousands of dollars)

	1993		1992		1991	
	Amount	% of Pre-tax Income	Amount	% of Pre-tax Income	Amount	% of Pre-tax Income
Federal Income Tax, per Statement of Income						
Current	$ 6,324		$ 530		$ 515	
Deferred and other (see Note 1)						
1989 Settlement						
Shoreham property	4,753		3,806		10,677	
Bokum Resources Corporation	—		—		20,400	
Rate moderation component	(30,511)		10,351		77,715	
Other 1989 Settlement items	11,396		8,622		872	
Net operating loss carryforward	78,708		(14,121)		(14,510)	
Shoreham post settlement costs	62,993		60,125		50,375	
Contractor litigation settlement	(503)		—		(18,758)	
Accelerated tax depreciation	32,101		35,951		30,447	
Call premiums	(5,460)		35,441		18,496	
Ratemaking and performance plan	14,369		17,680		(371)	
Other items	(1,894)		2,577		5,795	
Total Deferred and Other	165,952		160,432		181,138	
Total Federal Income Tax Expense	172,276		160,962		181,653	
Net Income	296,563		301,974		305,538	
Net Income Before Federal Income Tax	$ 468,839		$ 462,936		$ 487,191	
Statutory Federal Income Tax	$ 164,094	35.0%	$ 157,398	34.0%	$ 165,645	34.0%
Additions (reductions) in federal income tax						
1989 Settlement						
Shoreham property	4,256	0.9	4,003	0.9	4,003	0.8
Allowance for funds used during construction	(2,304)	(0.5)	(4,118)	(0.9)	(1,310)	(0.3)
Tax credits	(6,871)	(1.5)	(6,586)	(1.4)	(2,980)	(0.6)
Excess of book depreciation over tax depreciation	12,437	2.7	12,193	2.6	13,108	2.7
Interest capitalized	3,443	0.7	2,947	0.6	4,232	0.9
Other items	(2,779)	(0.6)	(4,875)	(1.0)	(1,045)	(0.2)
Total Federal Income Tax Expense	$ 172,276	36.7%	$ 160,962	34.8%	$ 181,653	37.3%

Note 11. Segments of Business

The Company is a public utility engaged in the generation, distribution and sale of electric energy and the purchase, distribution and sale of natural gas to 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 (excluding common), accrued unbilled revenues, gas in storage, fuel and deferred charges (excluding common). Assets utilized for overall Company operations consist of other property and investments, cash and cash equivalents, special deposits, accounts receivable, prepayments and other current assets, unamortized debt expense and other deferred charges.

(In thousands of dollars)

For year ended December 31	1993	1992	1991
Operating revenues			
Electric	$ 2,352,109	$ 2,194,632	$ 2,196,568
Gas	528,886	427,207	351,161
Total	$ 2,880,995	$ 2,621,839	$ 2,547,729
Operating expenses (excludes federal income tax)			
Electric	$ 1,513,452	$ 1,354,959	$ 1,254,702
Gas	427,138	352,777	338,295
Total	$ 1,940,590	$ 1,707,736	$ 1,592,997
Operating income (before federal income tax)			
Electric	$ 838,657	$ 839,673	$ 941,866
Gas	101,748	74,430	12,866
Total	940,405	914,103	954,732
AFC	(6,683)	(12,111)	(5,79[illegible]
Other income and deductions	(55,823)	(49,569)	(50,48[illegible]
Interest charges	534,072	512,847	523,816
Federal income tax—operating	184,854	172,998	169,452
Federal income tax—non-operating	(12,578)	(12,036)	12,201
Net income	$ 296,563	$ 301,974	$ 305,538
Depreciation and amortization			
Electric	$ 106,149	$ 104,034	$ 104,172
Gas	16,322	15,103	14,783
Total	$ 122,471	$ 119,137	$ 118,955
Construction and nuclear fuel expenditures*			
Electric	$ 170,941	$ 163,609	$ 144,356
Gas	133,752	109,295	93,195
Total	$ 304,693	$ 272,904	$ 237,551

*Includes non-cash allowance for other funds used during construction and excludes Shoreham post settlement costs.

(In thousands of dollars)

At December 31	1993	1992	1991
Identifiable assets			
Electric	$ 11,253,674	$ 8,867,205	$ 8,582,081
Gas	1,080,906	767,444	621,570
Total	12,334,580	9,634,649	9,203,651
Assets utilized for overall Company operations	1,121,457	1,129,810	934,844
Total Assets	$ 13,456,037	$ 10,764,459	$ 10,138,49[illegible]

Note 12. Quarterly Financial Information

(Unaudited)

(In thousands of dollars except earnings per common share)

		1993	1992
Operating revenues			
For the quarter ended	March 31	$ 760,451	$ 697,761
	June 30	604,871	580,498
	September 30	849,700	747,729
	December 31	665,973	595,851
Operating income			
For the quarter ended	March 31	$ 192,391	$ 179,741
	June 30	167,599	166,954
	September 30	263,984	256,800
	December 31	131,577	137,610
Net income			
For the quarter ended	March 31	$ 67,861	$ 66,706
	June 30	56,806	59,285
	September 30	144,549	141,388
	December 31	27,347	34,595
Earnings for common stock			
For the quarter ended	March 31	$ 53,286	$ 50,553
	June 30	42,451	41,040
	September 30	131,022	126,295
	December 31	13,696	20,132
Earnings per common share			
For the quarter ended	March 31	$ .48	$ .45
	June 30	.38	.37
	September 30	1.17	1.14
	December 31	.12	.18

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, during 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, 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, 1993 and 1992 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. 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, 1993 and 1992, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As discussed in Notes 8 and 10 to the financial statements, effective January 1, 1993, the Company changed its methods of accounting for postretirement benefits other than pensions and income taxes.

Ernst + Young

Melville, New York
February 4, 1994

Selected Financial Data

(In thousands of dollars)

Balance Sheet	1993	1992	1991	1990	1989
					Table 1
Assets					
Net utility plant	$ 3,347,557	$ 3,161,148	$ 3,002,733	$ 2,888,079	$ 2,781,157
Regulatory assets	7,610,639	5,221,143	4,951,086	4,723,357	4,335,845
Other assets	2,497,841	2,382,168	2,184,676	1,905,802	2,156,949
Total Assets	$ 13,456,037	$ 10,764,459	$ 10,138,495	$ 9,517,238	$ 9,273,951
Capitalization and Liabilities					
Capitalization					
Long-term debt	$ 4,870,340	$ 4,741,002	$ 4,986,166	$ 4,532,891	$ 4,531,429
Preferred stock — redemption required	649,150	557,900	524,912	527,550	541,187
Preferred stock — no redemption required	64,038	154,276	154,371	154,674	155,592
Common shareowners' equity	2,232,950	2,184,775	2,130,491	2,067,234	1,941,745
Total Capitalization	7,816,478	7,637,953	7,795,940	7,282,349	7,169,953
Liabilities	5,639,559	3,126,506	2,342,555	2,234,889	2,103,998
Total Capitalization and Liabilities	$ 13,456,037	$ 10,764,459	$ 10,138,495	$ 9,517,238	$ 9,273,951

(In thousands of dollars except per share amounts)

Summary of Operations					
					Table 2
Total revenues	$ 2,880,995	$ 2,621,839	$ 2,547,729	$ 2,456,902	$ 2,347,614
Total operating income (loss)	$ 755,551	$ 741,105	$ 785,280	$ 802,630	$ 620,423
Income (loss) before cumulative effect of accounting change	$ 296,563	$ 301,974	$ 305,538	$ 319,637	$ (95,803)
Cumulative effect of accounting change for unbilled gas revenues (net of tax)	—	—	—	$ 11,680	—
Earnings (loss) for common stock	$ 240,455	$ 238,020	$ 239,144	$ 263,156	$ (175,035)
Average common shares outstanding (000)	112,057	111,439	111,348	111,290	111,215
Earnings (loss) per common share					
Before cumulative effect of accounting change	$ 2.15	$ 2.14	$ 2.15	$ 2.26	$ (1.57)
Cumulative effect of accounting change	—	—	—	.10	—
Earnings (loss) per common share	$ 2.15	$ 2.14	$ 2.15	$ 2.36	$ (1.57)
Common stock dividends declared per share	$ 1.76	$ 1.72	$ 1.60	$ 1.25	$ .50
Common stock dividends paid per share	$ 1.75	$ 1.71	$ 1.55	$ 1.125	$ .25
Book value per common share at year end	$ 19.88	$ 19.58	$ 19.13	$ 18.57	$ 17.45
Common shareowners at year end	94,877	86,111	90,435	82,903	85,142

(In thousands of dollars)

Operations and Maintenance Expense Details					
					Table 3
Total payroll and employee benefits	$ 410,329	$ 413,817	$ 398,000	$ 357,689	$ 329,694
Less — Charged to construction and other	116,988	124,076	123,838	97,650	117,761
Payroll and employee benefits charged to operations	293,341	289,741	274,162	260,039	211,933
Fuels — electric operations	287,349	282,138	354,859	444,458	461,576
Fuels — gas operations	248,559	182,201	175,046	175,877	188,139
Purchased power costs	292,136	280,914	197,154	168,749	128,368
Fuel cost adjustments deferred	(453)	(3,469)	41,643	(2,085)	(5,631)
Total Fuel and Purchased Power	827,591	741,784	768,702	786,999	772,452
All other	228,319	208,204	248,597	215,770	215,373
Total Operations and Maintenance Expense	$ 1,349,251	$ 1,239,729	$ 1,291,461	$ 1,262,808	$ 1,199,758
Employees at December 31	6,337	6,541	6,605	6,630	6,239

(In thousands of dollars)

Electric Operating Income	1993	1992	1991	1990	1989
					Table 4
Revenues					
Residential	$ 1,145,891	$ 1,045,799	$ 1,047,490	$ 997,868	$ 915,644
Commercial and industrial	1,132,487	1,076,302	1,070,098	1,017,387	981,740
Other system revenues	49,790	49,395	47,838	46,673	42,232
Total system revenues	2,328,168	2,171,496	2,165,426	2,061,928	1,939,616
Sales to other utilities	12,872	9,997	23,040	24,140	42,880
Other revenues	11,069	13,139	8,102	9,592	792
Total Revenues	2,352,109	2,194,632	2,196,568	2,095,660	1,983,288
Expenses					
Operations — fuel and purchased power	579,032	559,583	593,656	611,122	584,313
Operations — other	306,116	294,909	296,798	271,608	237,931
Maintenance	111,765	105,341	127,446	118,545	115,502
Depreciation and amortization	106,149	104,034	104,172	98,022	91,759
Base financial component amortization	100,971	100,971	100,971	100,971	50,485
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)	(79,359)	(39,679)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)	(9,214)	(4,607)
Other regulatory amortizations	(17,082)	(21,984)	10,375	14,427	1,248
Rate moderation component	88,667	(30,444)	(228,572)	(297,214)	(131,167)
Regulatory liability component	—	—	—	—	793,592
Jamesport amortization	—	—	—	—	104,160
Operating taxes	326,407	331,122	338,429	322,197	312,456
Federal income tax — current	6,324	530	515	3,138	14,612
Federal income tax — deferred and other	158,941	158,908	173,259	169,274	(738,500)
Total Expenses	1,678,717	1,514,397	1,428,476	1,323,517	1,392,105
Electric Operating Income	$ 673,392	$ 680,235	$ 768,092	$ 772,143	$ 591,183

(In thousands of dollars)

Gas Operating Income	1993	1992	1991	1990	1989
					Table 5
Revenues					
Residential — space heating	$ 310,109	$ 243,950	$ 190,976	$ 198,734	$ 209,192
— other	39,515	33,035	29,383	30,854	31,692
Non-residential — space heating	106,140	90,363	70,938	68,441	72,351
— other	33,181	29,094	25,515	26,501	28,674
Total firm revenues	488,945	396,442	316,812	324,530	341,909
Interruptible revenues	24,028	19,658	21,686	30,515	19,226
Total system revenues	512,973	416,100	338,498	355,045	361,135
Other revenues	15,913	11,107	12,663	6,197	3,191
Total Revenues	528,886	427,207	351,161	361,242	364,326
Expenses					
Operations — fuel	248,559	182,201	175,046	175,877	188,139
Operations — other	81,692	77,300	78,469	68,910	59,587
Maintenance	22,087	20,395	20,046	16,746	14,286
Depreciation and amortization	16,322	15,103	14,783	12,862	11,671
Regulatory amortizations	(962)	(88)	—	—	—
Operating taxes	59,440	57,866	49,951	48,120	51,935
Federal income tax — current	—	—	—	500	—
Federal income tax — deferred and other	19,589	13,560	(4,322)	7,740	9,468
Total Expenses	446,727	366,337	333,973	330,755	335,086
Gas Operating Income	$ 82,159	$ 60,870	$ 17,188	$ 30,487	$ 29,240

	1993	1992	1991	1990	198
Electric Sales and Customers					Table 6
Sales — millions of kWh					
Residential	7,118	6,788	7,023	7,022	7,063
Commercial and industrial	8,257	8,181	8,322	8,359	8,636
Other	449	471	469	472	470
System sales	15,824	15,440	15,814	15,853	16,169
Sales to other utilities	304	227	598	532	633
Total Sales	16,128	15,667	16,412	16,385	16,802
Customers — monthly average					
Residential	905,997	902,885	898,974	895,294	890,406
Commercial and industrial	102,254	101,838	101,740	101,562	100,481
Other	4,553	4,593	4,540	4,504	4,452
Customers — total monthly average	1,012,804	1,009,316	1,005,254	1,001,360	995,339
Customers — total at year end	1,011,965	1,009,028	1,005,363	1,001,441	996,488
Residential					
kWh per customer	7,856	7,518	7,812	7,844	7,932
Revenue per kWh	16.10¢	15.41¢	14.92¢	14.21¢	12.96¢
Commercial and Industrial					
kWh per customer	80,749	80,346	81,797	82,304	85,943
Revenue per kWh	13.72¢	13.16¢	12.86¢	12.17¢	11.37¢
System					
kWh per customer	15,631	15,297	15,731	15,832	16,245
Revenue per kWh	14.71¢	14.06¢	13.69¢	13.01¢	12.0
Gas Sales and Customers					Table 7
Sales — thousands of dth					
Residential — space heating	37,191	35,089	29,687	29,810	32,024
— other	3,297	3,203	3,195	3,448	3,491
Non-residential — space heating	14,366	13,662	11,636	11,271	11,548
— other	4,329	4,338	4,171	4,352	4,539
Total firm sales	59,183	56,292	48,689	48,881	51,602
Interruptible sales	5,920	5,090	4,538	6,347	5,300
Off system sales	2,894	—	—	—	—
Total Sales	67,997	61,382	53,227	55,228	56,902
Customers — monthly average					
Residential — space heating	233,882	227,834	220,562	211,400	204,982
— other	166,974	169,189	171,581	176,000	179,415
Non-residential — space heating	32,783	31,666	30,453	29,072	27,733
— other	10,631	10,777	11,003	11,310	11,517
Total firm customers	444,270	439,466	433,599	427,782	423,647
Interruptible customers	542	531	472	410	359
Customers — total monthly average	444,812	439,997	434,071	428,192	424,006
Customers — total at year end	446,384	442,117	436,853	430,571	426,060
Residential					
dth per customer	101.0	96.4	83.9	85.8	92.4
Revenue per dth	$ 8.64	$ 7.23	$ 6.70	$ 6.90	$ 6.78
Non-residential					
dth per customer	430.6	424.1	381.3	386.9	409.9
Revenue per dth	$ 7.45	$ 6.64	$ 6.10	$ 6.08	$ 6.28
System					
dth per customer	146.4	139.5	122.6	128.9	134.2
Revenue per dth	$ 7.88	$ 6.78	$ 6.36	$ 6.43	$ 6.35

Electric Operations	1993	1992	1991	1990	1989
					Table 8
Energy — millions of kWh					
Net generation	10,514	10,592	13,570	13,981	15,220
Power purchased — net	6,719	6,211	3,638	2,989	2,087
Total system requirements	17,233	16,803	17,208	16,970	17,307
Company use and unaccounted for	(1,387)	(1,363)	(1,395)	(1,117)	(1,138)
System sales	15,846	15,440	15,813	15,853	16,169
Sales to other utilities	304	227	598	532	633
Total Energy Available	16,150	15,667	16,411	16,385	16,802
Peak Demand — mW					
Station coincident demand	2,931	2,975	3,085	3,260	3,178
Power purchased — net	1,036	636	819	426	510
System Peak Demand	3,967	3,611	3,904	3,686	3,688
System Capability — mW					
LILCO stations	4,063	4,091	4,078	4,077	4,066
Nine Mile Point 2 (LILCO's 18% share)	188	188	194	194	194
Firm purchases — net	548	432	423	408	400
Total Capability	4,799	4,711	4,695	4,679	4,660
Fuel Consumed for Electric Operations					
Oil — thousands of barrels	9,740	10,656	15,314	16,401	20,480
Gas — thousands of dth	36,269	34,475	32,924	36,477	26,490
Nuclear — thousands of mW days	181	124	154	108	105
Total — billions of Btu	98,025	102,126	129,937	139,874	154,669
Dollars per million Btu	$ 2.79	$ 2.62	$ 2.61	$ 3.07	$ 2.86
Cents per kWh of net generation	2.97¢	2.76¢	2.73¢	3.24¢	3.06¢
Heat rate — Btu per net kWh	10,628	10,558	10,484	10,564	10,704
Fuel Mix (Percentage of system requirements)					
Oil	33%	37%	50%	56%	67%
Gas	19	19	18	20	13
Purchased Power	41	38	25	20	16
Nuclear Fuel	7	6	7	4	4
Total	100%	100%	100%	100%	100%

Gas Operations					
					Table 9
Energy — thousands of dth					
Natural gas	69,970	64,911	55,579	55,407	60,359
Manufactured gas and change in storage	(68)	48	60	(15)	53
Total Natural and Manufactured Gas	69,902	64,959	55,639	55,392	60,412
Total system requirements	69,902	64,959	55,639	55,392	60,412
Company use and unaccounted for	(1,905)	(3,577)	(2,412)	(164)	(3,510)
Total Energy Available	67,997	61,382	53,227	55,228	56,902
Maximum Day Sendout — dth	485,896	448,726	435,050	406,177	462,610
System Capability — dth per day					
Natural gas	561,584	561,584	507,344	507,344	461,788
LNG manufactured or LP gas	120,700	120,700	128,200	128,200	145,600
Total Capability	682,284	682,284	635,544	635,544	607,388
Calendar Degree Days (67-year average 5,027)	4,899	5,066	4,378	4,139	5,169

Corporate Information

Executive Offices
175 East Old Country Road
Hicksville, New York 11801

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

Annual Meeting
The Annual Meeting of Shareowners will be held on Tuesday, April 12, 1994 at 3:00 p.m. In connection with this meeting, proxies will be solicited by the Company.

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

Common Stock Prices

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 for the Company's common stock for the years 1993 and 1992 were as follows:

	1993		1992	
	High	Low	High	Low
First Quarter	28¾	24⅞	24⅝	22⅛
Second Quarter	28¼	24¾	24¼	22⅜
Third Quarter	29⅝	27	25⅝	23⅜
Fourth Quarter	27¾	23¼	25⅞	23⅝

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
President
Polytechnic University

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

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

Winfield E. Fromm
Retired Vice President
Eaton Corporation
Electrical Engineering

Vicki L. Fuller
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
Director
Long Island Community
Foundation

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 and
Chief Financial Officer

William N. Dimoulas
Vice President
Information Systems
and Technology

Robert X. Kelleher
Vice President
Human Resources

John D. Leonard, Jr.
Vice President
Corporate Services and
Nuclear Operations

Adam M. Madsen
Vice President
Corporate Planning

Brian R. McCaffrey
Vice President
Administration

Joseph W. McDonnell
Vice President
External Affairs

William G. Schiffmacher
Vice President
Electric Operations

Robert B. Steger
Vice President
Fossil Production

William E. Steiger, Jr.
Vice President
Engineering and Construction

Walter F. Wilm, Jr.
Vice President

Edward J. Youngling
Vice President
Customer Relations
and Conservation

Robert J. Grey
General Counsel

Theodore A. Babcock
Treasurer

Kathleen A. Marion
Corporate Secretary and
Assistant to the Chairman

Thomas J. Vallely, III
Controller

Herbert M. Leiman
Assistant General Counsel
and Assistant Corporate
Secretary

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