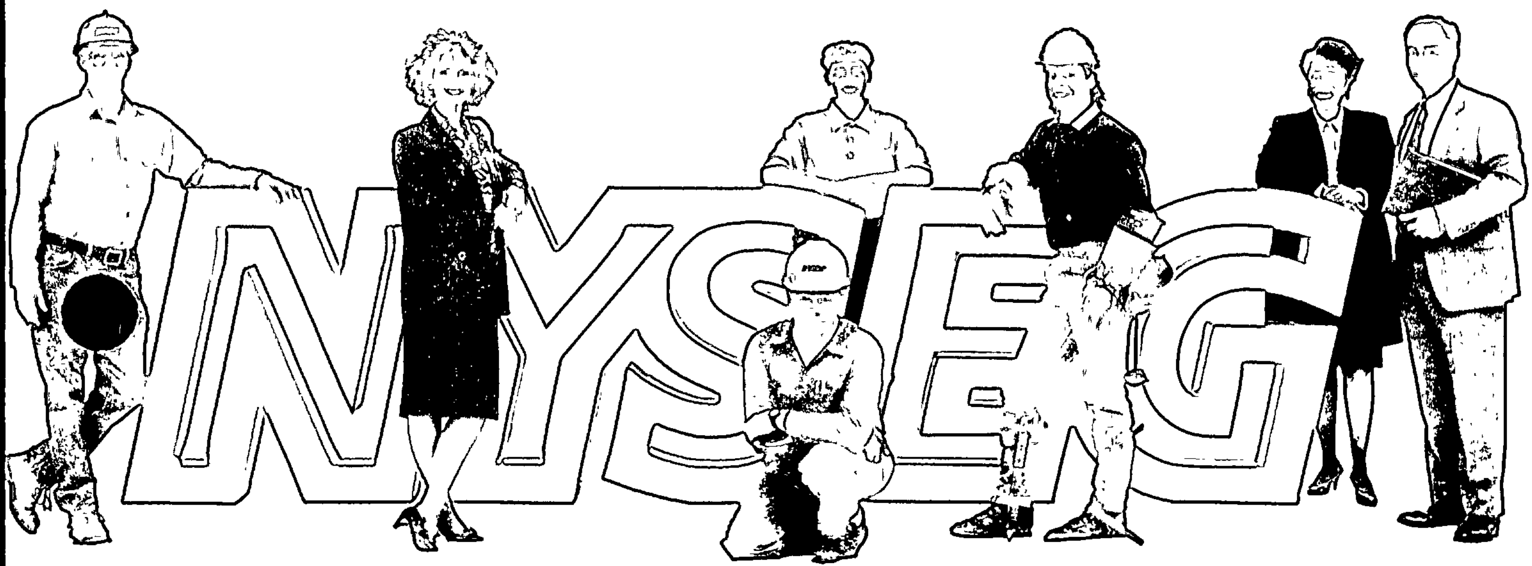
New York State Electric & Gas Corporation

1992 Annual Report



Meeting the Competition . . . Together

ABOUT THE COVER

More than ever before, employees with diverse backgrounds and skills from throughout the NYSEG organization are working together. They are guided by the objectives of our five-year strategic plan:

- to improve customer value
- to increase energy-efficient sales and develop new markets
- to enhance relations with regulators and elected officials
- to enhance employees' contributions to meeting the challenges of competition

BUTCH BOUCHER
GAS FITTER 1ST CLASS
Butch and his coworkers fill many important roles. As natural gas leak investigators, they are irreplaceable members of the NYSEG safety team. As high bill investigators, they perform an important customer service function. They also set new meters, the final step in bringing natural gas to our new customers.

DEBBIE FENDICK
MARKETING ADMINISTRATOR
Employees in our field organization close natural gas sales, but their efforts are supported by a corporate organization. Debbie is a member of the corporate team that monitors marketing programs, coordinates advertising and promotion, and analyzes information. In 1992, the natural gas marketing group shattered their performance goal.

SYBIL EDWARDS
METER READER - COLLECTOR
In this time of sweeping change, one thing hasn't changed: meters still have to be read so that customers can be billed for the energy they have used. Sybil and more than 120 of her colleagues across the state do their job well—more than 95 percent of the bills we send out are based on actual meter readings and not estimates.

KEN BRONSON
PLANT MAINTENANCE PLANNER
Proper planning and execution of maintenance procedures at our generating stations are critical to reliable electric service. They are also important elements in electric generating efficiency, which helps hold down production costs. The efficiency of our electric generating system stood at third in the country in 1991, the most recent year for which rankings are complete, thanks in part to the efforts of Ken and his colleagues.

MARK SEYMOUR
LINE MECHANIC 1ST CLASS
Imagine this: someone who's almost invisible except when the lights go out. That describes Mark and his coworkers. Although they construct electric lines and do complex maintenance work on energized lines, their efforts are most apparent during an electric outage. Fortunately, outages don't occur very often—our service reliability exceeds 99.96 percent.

SANDY JOHNSON
MANAGER -
WORK FORCE DIVERSITY
The human resources function is the oil that keeps an organization running smoothly and Sandy is an important member of the human resources team at NYSEG. She plans and implements affirmative action programs, ensures compliance with those programs and continually evaluates them.

FRANK SCOLLAN
TEAM LEADER -
PROMOTIONAL DEVELOPMENT
Frank is a member of the Electric Business Unit marketing team that has been focusing on demand-side management (DSM), a series of programs to help our customers use electricity efficiently. In 1992, these programs reduced our customers' electricity use by more than 139 million kilowatt-hours while we earned more than $15 million in DSM incentives.

CONTENTS

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COMPANY PROFILE

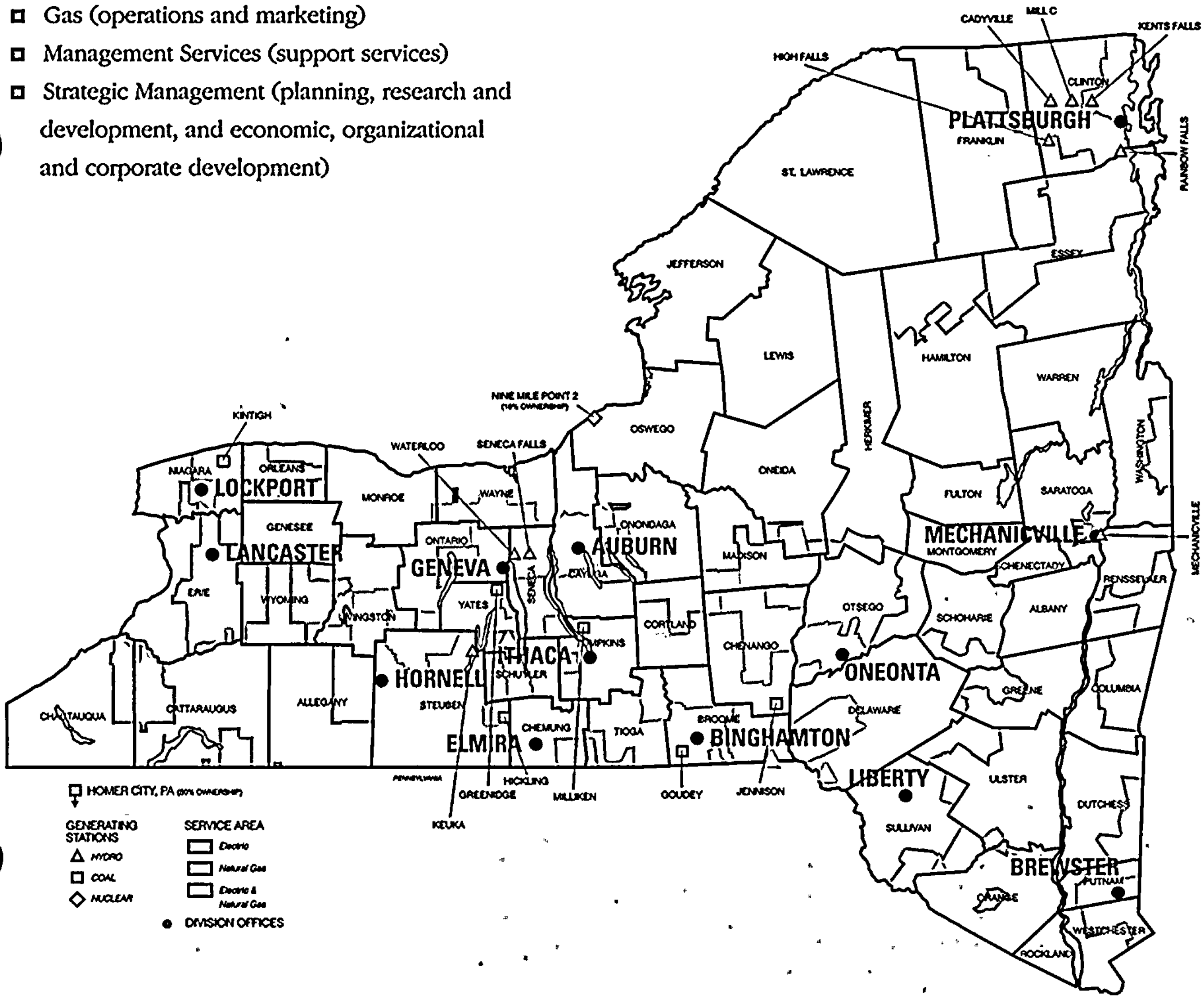
New York State Electric & Gas Corporation (NYSEG) is an investor-owned utility that traces its roots to the Ithaca Gas Light Company which began operations in 1852. Today our 4,888 employees serve 784,000 electric customers and 224,000 natural gas customers in suburban and rural upstate New York. High-tech firms, light industry, agriculture, colleges and universities, and recreational facilities support the area's economy.

We are composed of four business units:

- Electric (operations and marketing)
- Gas (operations and marketing)
- Management Services (support services)
- Strategic Management (planning, research and development, and economic, organizational and corporate development)

Our total operating revenues in 1992 were approximtely $1.7 billion and total assets were approximately $5.2 billion, making us the second largest utility in upstate New York.

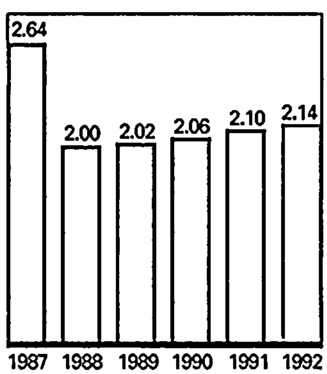
We generated almost 18 billion kilowatt-hours of electricity in 1992 at seven coal-fired generating stations, several small hydroelectric generating stations and one nuclear generating station. We also delivered more than 56 million dekatherms of natural gas purchased from pipeline companies, marketers and producers.



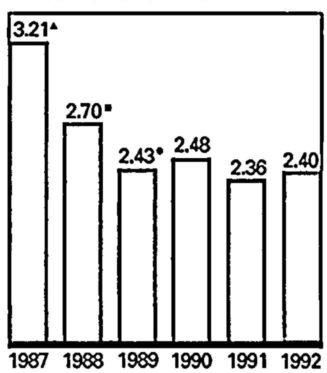
FINANCIAL HIGHLIGHTS

	1992	1991	% CHANGE
AT DECEMBER 31			
Total Assets (000)	$5,176,428	$4,924,836	5
Capitalization (000)	$3,630,901	$3,463,112	5
Capital Structure (includes current maturities):			
Long-term Debt	50.5%	52.2%	(3)
Preferred Stock	7.2%	7.7%	(6)
Common Equity	42.3%	40.1%	5
OPERATING RESULTS (000)			
Total Operating Revenues	$1,691,689	$1,555,815	9
Operating Expenses	$1,367,926	$1,234,720	11
Net Income	$183,968	$168,643	9
Earnings for Common Stock	$162,973	$148,313	10
Retail Megawatt-hour Sales	13,294	13,107	1
Dekatherms of Natural Gas Delivered	56,366	42,404	33
PER COMMON SHARE			
Earnings	$2.40	$2.36	2
Dividends	$2.14	$2.10	2
Book Value (year end)	$22.85	$22.16	3
Market Value (year end)	$32.50	$29.00	12
OTHER INFORMATION			
Common Stock Price Range	$26 1/8 - 32 3/4	$24 - 29 5/8	
Return on Average Equity	10.6%	10.7%	(1)
Market-to-Book Ratio	142%	131%	8
Average Common Shares			
Outstanding (000)	67,972	62,906	8
Common Shareholders (year end)	61,183	59,593	3

DIVIDENDS
DOLLARS PER SHARE



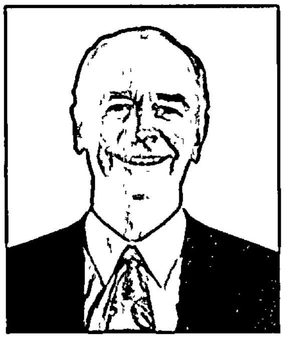
EARNINGS
DOLLARS PER SHARE



▲ Excluding the effects of the write-off of Nine Mile Point 2 and Jamesport disallowed costs, and an accounting change for income taxes.

■ Excluding the effect of an April 1988 adjustment to the 1987 Nine Mile Point 2 write-off.

• Excluding the effect of a December 1989 adjustment to the 1987 Nine Mile Point 2 write-off.



NYSEG has positioned itself to take full advantage of the opportunities being presented to us and we have every confidence we will be one of the winners.

To my fellow stockholders:

It is with a great sense of responsibility and pride that I write to you.

In past years I have started this letter with a discussion of earnings. This year I am going to break that tradition because I want to discuss three critical issues: change, competition and challenges.

Perhaps the single most important piece of information that you, as an owner of NYSEG, need to know is the undeniable fact that the utility industry is in the midst of unprecedented change. Gone forever are the days of a stable and predictable business climate. Utility companies have to learn how to compete if they are going to succeed. Many changes are causing this new, highly competitive environment. They include the potential for open access to our electric transmission lines, the reality of non-utility generation and the Federal Energy Regulatory Commission's Order 636 which is designed to create more competition in the natural gas business. These and other emerging issues are challenging what used to be the protected domain of regulated energy utilities.

It is this infusion of competition that is the driving force behind the significant challenges we face. It is this same infusion that will create enormous opportunities for the companies that have the vision, skill and resources to take advantage of them. NYSEG will be one of those companies.

Let me emphasize that in the rapidly changing and competitive environment we are dealing with every day, there will be winners and losers. NYSEG has positioned itself to take full advantage of the opportunities being presented to us and we have every confidence we will be one of the winners. But, making this happen will require more than just hope and good intentions. It will require implementation of our comprehensive strategic plan, an ability to immediately respond to an ever-changing business environment and a results-oriented work force.

NYSEG had the foresight to recognize, early on, the enormity of the changes the industry is now experiencing. More than three years ago, we began implementing Vision 2000, the details of which I have shared with you in past communications. I am happy to report the actions we have taken are beginning to pay dividends, both tangible and intangible.

At the core of our strategy is a shift in our organizational structure and corporate culture. Changing to a business unit structure has accelerated decision making, improved our ability to control costs and enabled us to become more focused. Our change in corporate culture—the way we think and work, and the environment in which we work—is guided at each juncture by our shared values: excellence, innovation, integrity, teamwork, caring and accountability. Each and every employee must focus on these values in order for us to build a firm foundation for NYSEG's future. We are already seeing results.

It's no accident that earnings have increased to $2.40 per share, up 4 cents from 1991. It is a direct result of the NYSEG team working together to improve shareholder return.

Three other pieces of financial information are also important to note:

- Fitch Investors Service, Inc. upgraded its ratings of our first mortgage bonds and preferred stock and Moody's Investors Service upgraded its ratings of our first mortgage bonds and unsecured pollution control bonds. These ratings are now the highest they have been in 12 years.
- In 1992, we refinanced $250 million of first mortgage bonds. This will save our customers more than $3 million a year. We have refinanced more than $1 billion in debt since the end of 1987 and our embedded cost of debt has decreased from 9.8 percent to 7.7 percent.
- Our common equity ratio rose from 33 percent at the end of 1987 to the present level of 43 percent. Over the same period, our long-term debt ratio decreased from 62 percent to 49 percent.

Meanwhile, our natural gas business continues to grow. In 1992, it contributed 8 cents a share to earnings, a significant improvement from 1991's loss of 2 cents a share. We fully expect further gains in 1993 because of our emphasis on selling this abundant, clean-burning fuel and developing new markets. The Gas Business Unit has also made us an industry leader in promoting natural gas vehicles.

We have also made significant gains in sparing our customers the financial burden of unneeded and uneconomical electricity from non-utility generators (NUGs). We are required by federal law to enter into contracts with NUGs to buy electricity that our customers do not need. We were required by state law to pay 6 cents a kilowatt-hour (kwh) for power from qualifying facilities, far higher than our own production cost. Fortunately, at the tenacious urging of NYSEG and other utilities in New York State, the 6-cent law was repealed by the Legislature in June 1992 and signed into law by the Governor in August 1992. Unfortunately, contracts signed while the 6-cent requirement was in effect are still valid. We had signed contracts for more than 900 megawatts (mw) of electricity by the time the law was repealed.

Had we done nothing, these contracts would have cost our customers more than $3 billion for unneeded and over-priced electricity. However, we have taken a leadership role among electric utilities in fighting for our customers on three fronts:

- NUG contract requirements are strictly enforced. So far, cancellations have saved our customers $240 million and eliminated 113 mw of planned generation.
- We chose to award no contracts under a mandated bidding program for 100 mw of generation. That saved our customers approximately $80 million.
- We have aggressively negotiated the termination of two other contracts with NUG developers totaling 134 mw. We paid more than $45 million for these contract terminations which will save our customers $650 million.

Let me emphasize that our biggest concern with NUGs rested with the 6-cent law here in New York State. We believe that, if operated in a true market environment, the NUG industry can increase competition to the benefit of ratepayers.

LETTER TO STOCKHOLDERS

At this time, we are actively engaged in discussions regarding a multi-year rate settlement agreement with the staff of the Public Service Commission and other interested parties. By working cooperatively with regulators we can eliminate much of the contention sometimes associated with the more traditional approach to ratemaking. At the same time, by encouraging broad involvement, win-win solutions can be developed. This regulatory philosophy is absolutely essential in order to address the long-term economic challenges we face.

We also continue to believe that diversification, whether in the regulated or nonregulated arena, will play an important role in NYSEG's future. While the strength of our core electric and natural gas businesses remains our focus, we are actively evaluating a number of corporate development opportunities for investment. Let me assure you that we will do nothing to compromise our financial integrity.

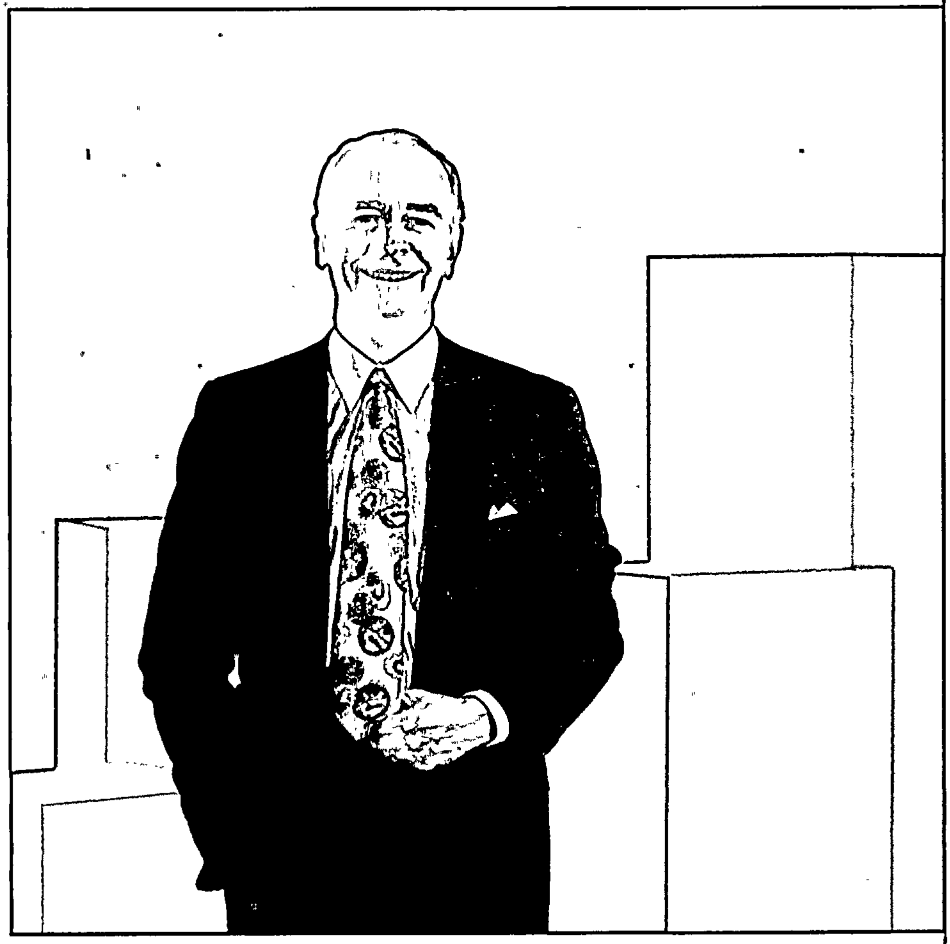
Our Work Simplification program, a continuous improvement process, is well underway and has resulted in substantial changes in the way we do business. Twenty business processes were comprehensively reviewed in 1992. More information about Work Simplification is provided later in this report, but let me tell you that the changes we are implementing will reduce our cost of doing business, make us more responsive to the marketplace and build on our commitment to teamwork. In 1993, we will continue to reinforce the corporate culture change now underway to assure that our employees are well prepared to meet competition head on.

In closing, I would like to share a personal experience with you. Quite often I have the opportunity to talk with NYSEG employees from across the state, whether at an employee meeting, a Speakers Club dinner or just in the hall at the office. On those occasions, I am reminded that our employees are the reason for our success during this time of change. They are the people who time and again have risen to challenges and they are truly our greatest asset. They haven't run from competition, they have welcomed it.

For the Board of Directors,

James A. Carrigg

James A. Carrigg
Chairman, President and
Chief Executive Officer
February 19, 1993



YEAR IN REVIEW

FEBRUARY
The Broome-Tioga Association for Retarded Citizens joined with us to start sorting and recycling surplus and scrap materials at our Investment Recovery Center.

MARCH
We sold five million shares of common stock at $27.25 per share, a 20 percent premium to book value. Proceeds were used to repay commercial paper which was issued to pay for construction.

APRIL
We received approval from the Public Service Commission (PSC) to invest in nonregulated subsidiaries in the areas of environmental services and energy-related businesses.

Our employee Speakers Club won the Edison Electric Institute's first Dillon Award for excellence in the development and presentation of speakers bureau programs.

INVESTMENT RECOVERY CENTER

JUNE
We reached agreement with Indeck Energy Services of Kirkwood, Inc. to terminate the purchase power agreement for the planned 55-megawatt (mw) Indeck-Kirkwood cogeneration project. This power was unneeded and uneconomical.

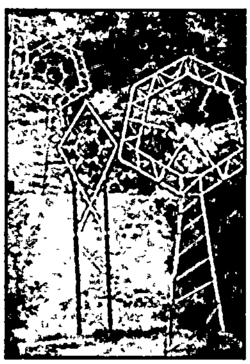
JULY
The PSC approved a 5 percent increase in electric rates and 4.1 percent increase in natural gas rates effective August 1.

Our high phase order transmission line, the first of its kind in the world, was energized. This power line, a research and development project, carries up to 73 percent more power in the same space as a traditional transmission line.

AUGUST
Texas businessman Boone Pickens, chairman of the Natural Gas Vehicle (NGV) Coalition, was the featured speaker at our second annual Northeast NGV Conference in Binghamton. More than 400 people attended.

We received permits from the New York State Department of Environmental Conservation for construction of an innovative pollution control system at Milliken Generating Station.

We joined a national research effort to investigate the use of cordless electric lawn mowers to reduce urban pollution.



HIGH PHASE ORDER TRANSMISSION LINE

OCTOBER
Jennison Station became the first generating facility in New York State to regularly burn tire chips to produce electricity.

BOONE PICKENS

We sold $150 million of 10-year first mortgage bonds at a coupon rate of 6.75 percent. Net proceeds were used in connection with the redemption of three series of first mortgage bonds. This refinancing will save our customers approximately $2 million a year in interest costs.

NOVEMBER
We filed requests for a 5.5 percent increase in electric rates and a 3.6 percent increase in natural gas rates to be effective in August 1993.

DECEMBER
We sold $100 million of 30-year first mortgage bonds at a coupon rate of 8.30 percent. Net proceeds were used in connection with the redemption of first mortgage bonds. This refinancing will save our customers approximately $1 million a year in interest costs.

Project SHARE, our emergency heating fund administered by the American Red Cross, celebrated its 10th anniversary. More than $2 million has been contributed to the fund by our customers, employees, retirees and stockholders. More than 10,000 grants have been provided to needy families to help pay their utility bills.

We reached agreement with Kamine/Besicorp Corning L.P. to terminate the purchase power agreement for the planned 79-mw South Corning cogeneration project. This power was unneeded and uneconomical.

MEETING THE COMPETITION

Change is not new to the energy industry. Fundamental change is.

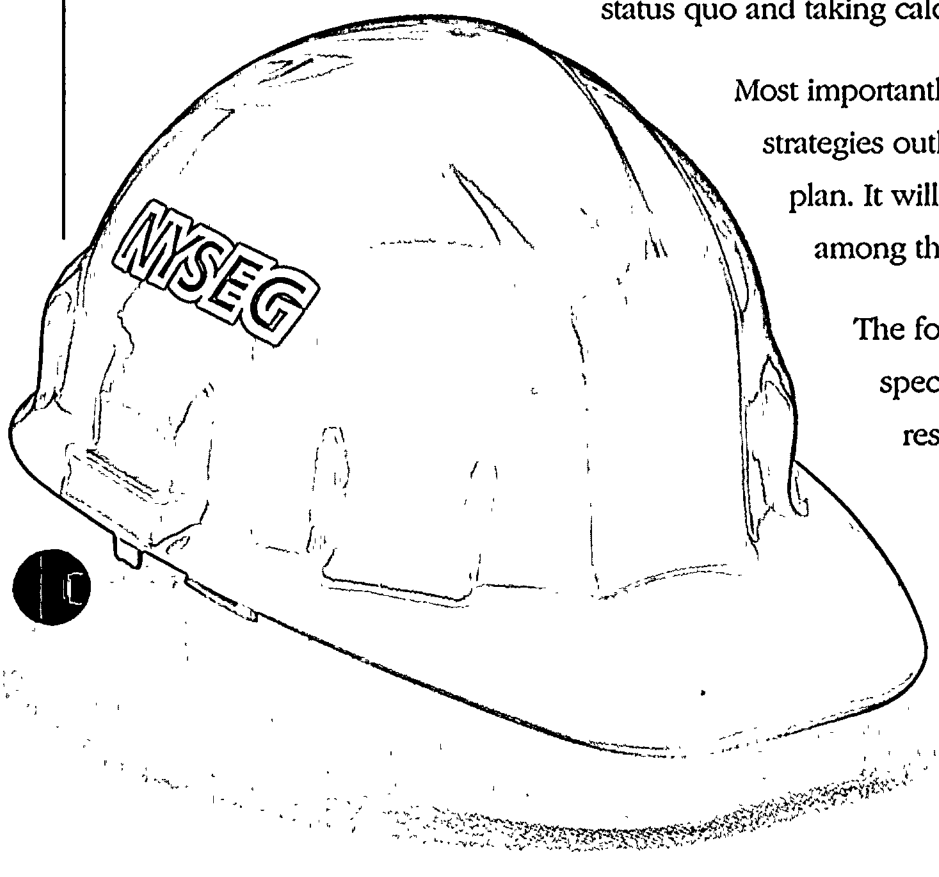
Now, for the first time since the first of NYSEG's predecessor companies began operating in Ithaca 140 years ago, we are faced with a new business environment. Public policy has changed, regulation has changed and competition is a reality.

Large customers are no longer forced to buy energy from us just because they happen to be located in our service area. They can generate their own electricity or purchase their own supply of natural gas directly from the source.

Fundamental change and competition mean that we must change our ways. Only those companies that are able to adapt and meet the challenges posed by competition will prosper in the 1990s. We have adopted a new spirit and are recommitted to working together for the good of NYSEG, challenging the status quo and taking calculated risks.

Most importantly we will concentrate on the strategies outlined in our five-year strategic plan. It will guide us to our goal: to be among the best utilities in the country.

The following pages highlight specific examples of some of our results to-date.

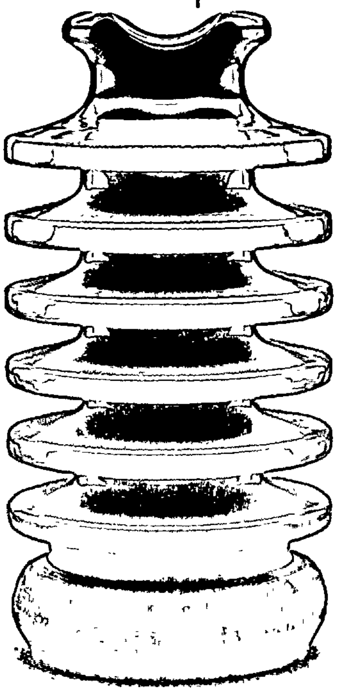


BUILDING CUSTOMER VALUE

Our customers deserve reasonable rates.

With that in mind, our goal is to maintain electric and natural gas price increases within the rate of inflation. To succeed, we must control costs.

We have already saved our customers almost $1 billion by terminating purchase power agreements with NUG developers. We have developed and implemented new budgeting procedures. We have also set ambitious targets for capital budgeting and investments and are continuing to pay particular attention to profitability and total return to stockholders. However, as important as controlling direct costs is, innovation and efficiency can also have a considerable impact on our financial picture. Here are some examples.



GENERATING EFFICIENCY: THIRD IN THE COUNTRY

In 1992, we spent more than $262 million for fuel, primarily coal, to generate electricity. If we are going to keep costs to a minimum, it is essential that we squeeze every kilowatt-hour out of every pound of coal.

Each year *Electric Light and Power* magazine ranks the operating performance of the top 100 utilities in the country. The most recent results are from 1991 and they speak to our success. Our generating system ranked first in New York State, for the eighth year in a row, and third in the country. Kintigh Station, which provides 691 megawatts (mw) of electricity to our customers, ranked fifth in the country among individual generating units.

ALTERNATIVE FUELS: A SUCCESS STORY

Jennison and Hickling generating stations were built in the 1940s and a second generating unit was added to each in the 1950s. Generating station technology has advanced markedly since then, yet their unique traveling grate design has given them new life. These traveling grates enable us to burn alternative fuels.

In October, Jennison Station became the first generating station in New York State to regularly burn tire chips mixed with coal. Its four boilers can consume up to 4.5 million tires—or 45,000 tons of tire chips—each year. This saves landfill space and saves money for our customers because it has the potential to reduce the amount of coal we purchase by up to 65,000 tons each year.

In December, Hickling Generating Station began testing a fuel mixture of coal and coal tar soil from an inactive manufactured gas plant (MGP) site. If the New York State Department of Environmental Conservation approves continuation of the project, it may be an environmentally responsible and economical way of disposing of coal tar byproducts from MGP sites.

THE CHALLENGE: To be a low-cost provider of energy services in the Northeast.

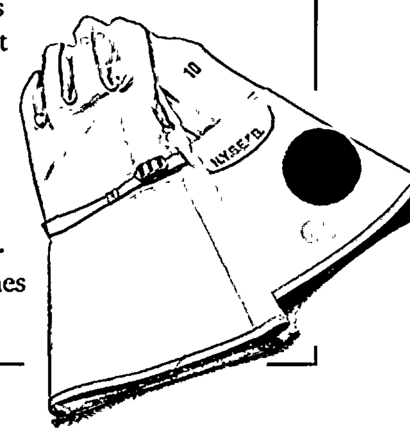
CALL CENTER: A PLUS FOR CUSTOMER SERVICE

At our new customer call center in Binghamton, we are centralizing the telephone and account maintenance functions from 42 offices scattered across our 19,000 square mile service area. This will save customers money, but the benefits go beyond savings.

Once the call center is in full operation in November 1993, it will offer customers expanded hours. Its telephone system and computers, manned by well-trained customer representatives, will allow us to meet our customers' changing needs and growing expectations. Customers will still be able to meet with our customer representatives face-to-face at local offices when necessary.

NATURAL GAS ENERGY MANAGEMENT: TRACKING SUPPLY AND DEMAND

We have just installed an advanced energy management system for our natural gas business. It provides control of natural gas flow from transmission lines into our



system and up-to-the second data on customer use around the state. The system will help us better manage natural gas supply planning and the purchase of natural gas. The Federal Energy Regulatory Commission's Order 636, which is designed to create more competition in the natural gas business, shifts responsibility for these matters to local distribution companies such as NYSEG. The energy management system will ensure that we get the least expensive natural gas possible to our distribution system.

PROTECTING THE ENVIRONMENT: AN INNOVATIVE APPROACH
Construction is about to begin on an innovative system to remove sulfur dioxide from flue gas at Milliken Generating Station. It will help us comply with the requirements of the Clean Air Act Amendments of 1990 and also demonstrate how we can continue to use the country's abundant supply of coal in an environmentally responsible manner. The project is unique in that it will use a German technology not currently in use in the U.S. The U.S. Department of Energy, through its Clean Coal Technology Program, and several industry research alliances will fund a portion of the $159 million project.

Most people see used tires as a disposal problem. We see them as an opportunity. In 1992, Jennison Station became the first generating facility in the state to be licensed to regularly burn tire chips mixed with coal. Some members of the tires-to-energy team are: (seated, from left) Ed Greenman, Mike Tesla and Fred Cannistra; (standing, from left) Iva Cunningham, Phil Murphy and Terry Barnard.

SEARCHING OUT OPPORTUNITIES TO GROW

Growth is important to our future.

It often comes with little effort during good economic times. However, the sluggish New York State economy and the success of our demand-side management (DSM) programs have kept growth to a minimum in recent years. In 1992, retail electric sales increased just 1 percent. Retail natural gas sales increased 32 percent largely because of the acquisition of Columbia Gas of New York in April 1991.

We are responding to the challenge of limited growth in several ways. First and foremost, we have reorganized our electric and natural gas marketing groups to quickly and effectively respond to the needs of our customers, as well as to concentrate on energy-efficient sales. Here are some additional examples.

NATURAL GAS: ACTIVITIES ON MANY FRONTS
With the Clinton Administration's new emphasis on natural gas, we are more excited than ever about the potential for our natural gas business. We are continuing to promote conversion to natural gas, extend natural gas distribution lines and evaluate

opportunities to obtain new natural gas service franchises. We also know that these efforts alone will not allow us to realize the potential that exists for natural gas in New York State. So, we are also pursuing several supply and storage opportunities that would enhance our ability to deliver a reliable supply of the least expensive natural gas possible.

ELECTRICITY: BLENDING CONSERVATION AND SALES

In 1992, our electric marketing team focused on DSM programs. While helping customers use electricity efficiently will remain important in 1993, we will also be actively selling electricity where it makes economic sense for customers and is environmentally responsible. We will be promoting efficient technologies such as infrared drying for manufacturing processes, ground source heat pumps and security lighting.

NATURAL GAS VEHICLES: A PROMISING MARKET

Our natural gas vehicle (NGV) program continues to gain momentum. In August, we held the second annual Northeast NGV Conference in Binghamton and in November, we installed a natural gas fueling station in Binghamton for several NYSEG vehicles and three natural gas-fueled transit buses.

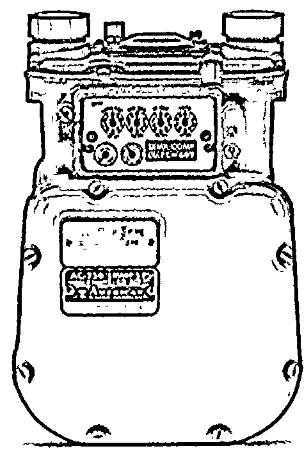
THE CHALLENGE: To boost energy-efficient sales and develop new markets.

NONREGULATED SUBSIDIARIES: A FRESH LOOK

We received permission from the Public Service Commission in April to invest in nonregulated subsidiaries in the areas of environmental services and energy-related businesses. However, after carefully re-evaluating the promising opportunities we had identified, we determined that any investment in those opportunities at this time would be unwise. We have now refocused our efforts on maintaining the financial strength of our core electric and natural gas businesses. We continue to believe that diversification will play an important role in our long-term success. We are actively evaluating a number of corporate development opportunites for investment.

ECONOMIC DEVELOPMENT: HELPING SHORE UP A SLUGGISH ECONOMY

Given New York State's economic climate, creating jobs is no easy task. Despite these challenging times, our economic development professionals continue to work with businesses interested in locating facilities in our service area. They are also concentrating on helping existing industrial customers expand. In 1992, their efforts resulted in the expansion or retention of 17 businesses. They are currently working closely with 12 Canadian businesses that will be making location decisions in 1993. The new year has also brought with it a renewed emphasis on working with state and local governments to strengthen the state's economy.



Gathering accurate data and analyzing that data in a timely manner is at the heart of identifying growth opportunities. Representatives of all four of our business units are working together on this process on an on-going basis. Some of the team members who have been involved in searching out opportunities are: (clockwise, from left) Sue Ward, Bob Rude, Rex Berntsson, Bob Irvin, Joe Vajda, Donna Vandenberg and Tom Ryan.

We are giving new emphasis to working together with regulators and elected officials toward positions that are beneficial to our stockholders and customers.

We worked with elected officials to help shape the Clean Air Act Amendments of 1990 rather than fight against passage, and we continue to be involved in related rulemaking. At the state level, we supported the repeal of New York State's law that required us to buy electricity from qualifying NUGs for 6 cents a kilowatt-hour. The result of the repeal of this law in 1992 will save New York State ratepayers billions of dollars. We are proud of results such as these, but there is still plenty to do.

A MULTI-YEAR RATE SETTLEMENT: DISCUSSIONS CONTINUE

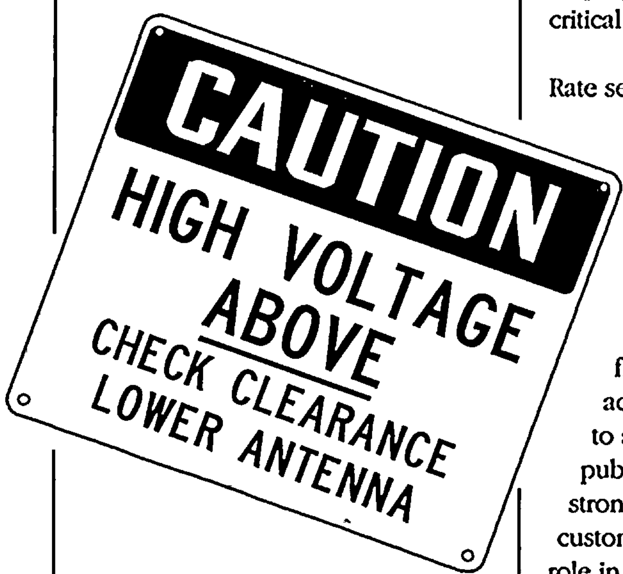
Since July, we have been working with the PSC staff and other interested parties toward a multi-year rate settlement agreement.

THE CHALLENGE: To align our objectives with public policy through stronger relationships with regulators and elected officials.

This process has been unique in that it has been less formal than usual rate proceedings. Everyone involved has had an equal voice and the process has been facilitated by a NYSEG employee using problem-solving techniques.

We believe a rate settlement agreement would allow our customers to better plan their energy budgets, while sparing them the expense of frequent rate proceedings. It would help us by freeing up resources that are used during rate proceedings, allowing for better planning and allowing employees to concentrate on other critical issues such as competition.

Rate settlement discussions, which are continuing, have contributed to improved relations with the PSC.



KEY ACCOUNTS: BUILDING A NEW RELATIONSHIP

Our major customers will figure prominently in the actions we will have to take to align our objectives with public policy. By building a stronger relationship with these customers, we can play an active role in strengthening the state's economy which will be to everyone's benefit. Both our electric and natural gas marketing groups now include personnel whose job it is to maintain contact with large customers and ensure that we are providing them with any services at our disposal that will help them be more competitive. As an off-shoot of these "key account" partnerships, we want to promote a common direction for economic growth in our service area.

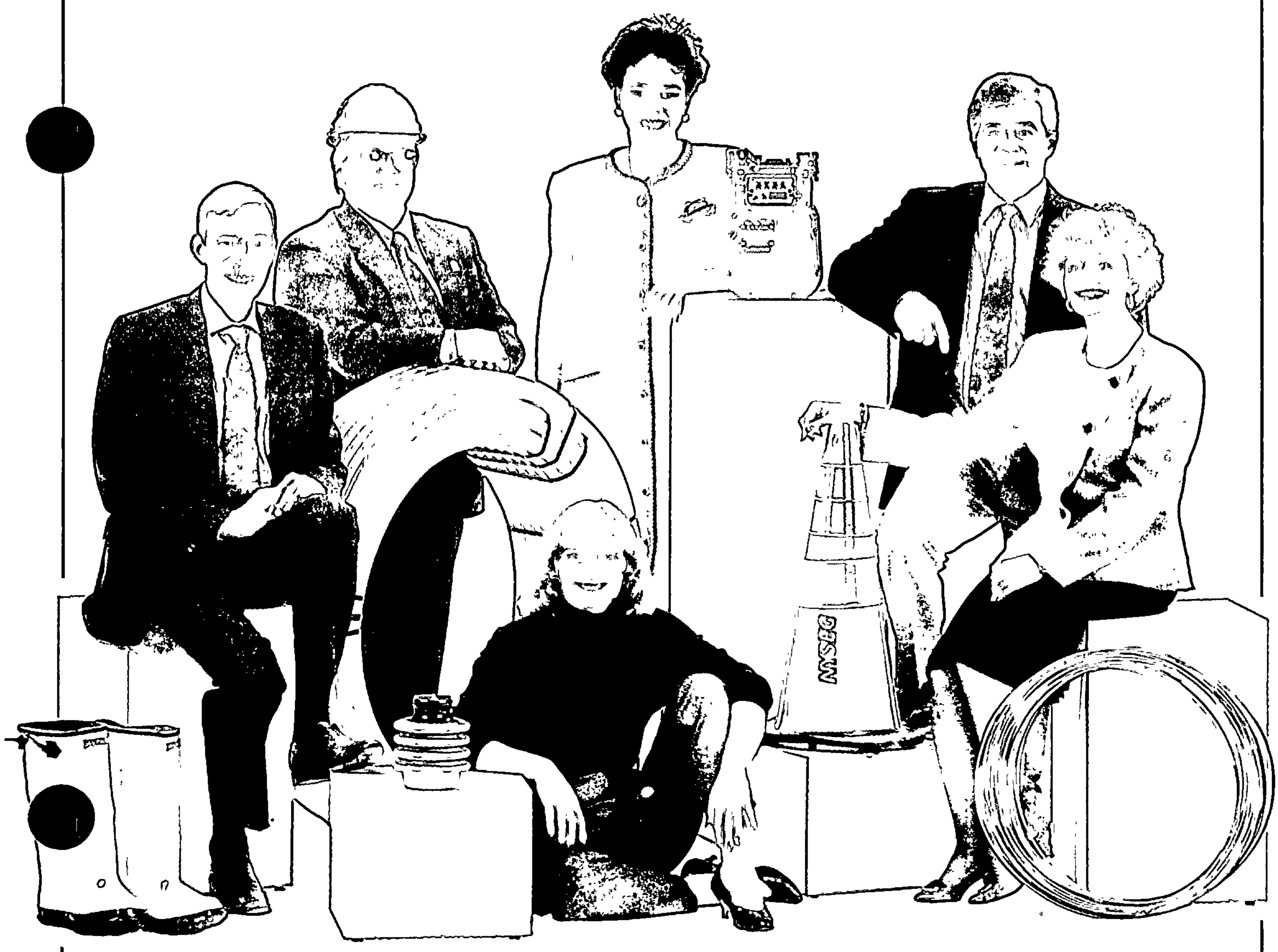
RATES: NOT THE SAME OLD APPROACH

We know that large customers need to hold down costs to remain competitive. So, we asked the PSC for permission to negotiate electric rates with large industrial customers who meet specific requirements. In January 1993, that request was approved. An interruptible service rate that will make natural gas more attractive to public authority customers, such as state and federal government facilities, was also approved by the PSC in January 1993.

REGULATORY RELATIONS: DEFINING GOALS

In 1993, we will further formalize our regulatory relations process by defining goals and assigning specific roles and responsibilities. We will also use our government relations program to promote streamlining of the regulatory process and further development of incentive regulation.

Whether we are helping customers conserve electricity, selling electricity where it makes economic sense for a customer or selling natural gas, our talented marketing representatives are on the front line. In 1992, the electric and natural gas teams each shattered their marketing goals. Representatives of the NYSEG marketing team are: (seated, from left) Charlie Collins, Cathy Smith and Patricia Edwards; (standing, from left) Gary Strong, Angela Sparks and Ralph Chester.



MEETING COMPETITION HEAD ON

Our employees have the talent and skills to make NYSEG successful in these changing times.

Every day, our employees are dealing with the dramatic changes in the energy industry. They have responded very well and they now recognize that this is not the same old business that it has always been. They know that we must respond to a competitive environment by working together, looking for new opportunities and taking more risks. Several efforts are already in place that will help us achieve our organizational capability challenge.

WORK SIMPLIFICATION: REAPING BENEFITS

Work Simplification was just introduced in 1992, but its impact has been dramatic. Simply stated, this process involves carefully examining how we perform specific tasks and developing recommendations for working more efficiently and cost-effectively.

Twelve employee teams completed a first round of work in 1992. Processes examined included business planning and budgeting, electric and natural gas sales management, vehicle management and employee development. Results included implementation of our new business planning and budgeting procedures, reorganization of our marketing departments, a reduction in the number of our vehicles and streamlining our advancement opportunity program.

Eight new teams then examined processes such as requesting new electric or natural gas service and determining vehicle needs for our natural gas business.

THE CHALLENGE:
To hone our competitive edge by pulling together.

One particularly noteworthy effort has already come from the second round of work simplification. A work group composed of representatives of management and System Council U-7 International Brotherhood of Electrical Workers (IBEW) convened to study the handling of grievances from IBEW employees. They reached agreement on an equitable way to handle future grievances and how to address a backlog of grievances awaiting arbitration.

By the end of November, our new call center in Binghamton will be responsible for handling customer calls for our entire service area. The call center will offer expanded customer service hours and will save money. Members of the call center team who are already on board include: (seated, from left) Nancy Hunt, Jim Hogan, Jean Mitchell and Sue Libous-Heenan; (standing, from left) Craig Hall, Hope Robinson, Rick Cerchiara and Helen Black.

WORK PLANNING:
INTEGRATING EFFORTS

Proper planning of work by employees is vital to enhancing our competitive position.

In past years, each salaried employee, together with his or her supervisor, prepared annual work plans based on what they understood as being important to the Company's success. That process has now changed. Business plans for each of our four business units now flow directly from the strategic plan, departmental plans are linked to the business unit plans and individual plans are linked to the departmental plans. Now every employee's efforts will directly contribute to achieving the objectives of our strategic plan.

Other efforts designed to make us more competitive by making employees more accountable for results include:

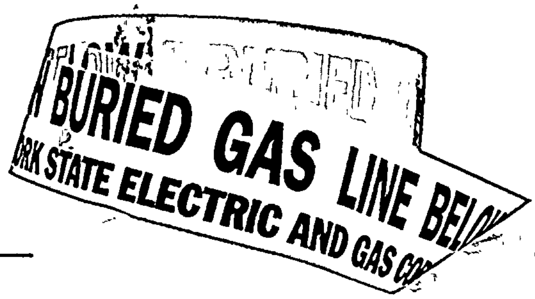
- Performance Up, an incentive award program for salaried employees. Our actual performance measured against customer service and earnings goals will determine the size of the incentive awards.
- Our suggestion program, I³, which encourages employees to submit well thought out solutions to problems. It has the potential to save money and streamline the way we operate.
- Continuation of Energy Into Action, a leadership and team building program for employees.

COMMUNICATIONS:
KEEPING EMPLOYEES INFORMED

Our third point of emphasis is continued evaluation and enhancement of internal communications. We must do our best to keep employees informed of what we are doing and why. Informed employees have the tools to be more productive and can make better decisions for the Company.

The strategic plan and our efforts thus far are only the beginning. While we will continue to focus on meeting the needs and expectations of our stockholders, customers and employees, the key strategies of the strategic plan will change as the environment in which we operate changes. In turn, each employee's energy must be directed to reflect those changes.

One thing is clear: as our employees continue to implement our strategic plan and use our business planning process, our stockholders and customers will reap the benefits.



BOARD OF DIRECTORS

First year elected in parentheses

Wells P. Allen, Jr. (1974)
Former Chairman and
Chief Executive Officer of the Corporation
Binghamton, NY

James A. Carrigg (1983)
Chairman, President and
Chief Executive Officer of the Corporation
Binghamton, NY

Alison P. Casarett (1979)
Dean of the Graduate School
Cornell University
Ithaca, NY

Everett A. Gilmour (1980)
Former Chairman of the Board and
Chief Executive Officer
The National Bank and Trust Company
of Norwich
Norwich, NY

Paul L. Gioia (1991)
Senior Vice President
First Albany Corporation
(Brokerage and Investment Banking Firm)
Albany, NY

John M. Keeler (1989)
Managing Partner
Hinman, Howard & Kattell
(Attorneys at Law)
Binghamton, NY

Allen E. Kintigh (1987)
Former President and
Chief Operating Officer of the Corporation
Binghamton, NY

Ben E. Lynch (1987)
President
Winchester Optical Company
(Manufacturer of Eyeglasses)
Elmira, NY

Alton G. Marshall (1971)
Senior Fellow
Nelson A. Rockefeller
Institute of Government
Albany, NY

David R. Newcomb (1979)
Former President and
Chief Executive Officer
Buffalo Forge Company
(Manufacturer of Heating, Ventilating
and Air Conditioning Equipment)
Buffalo, NY

Robert A. Plane (1982)
President
Wells College
Aurora, NY

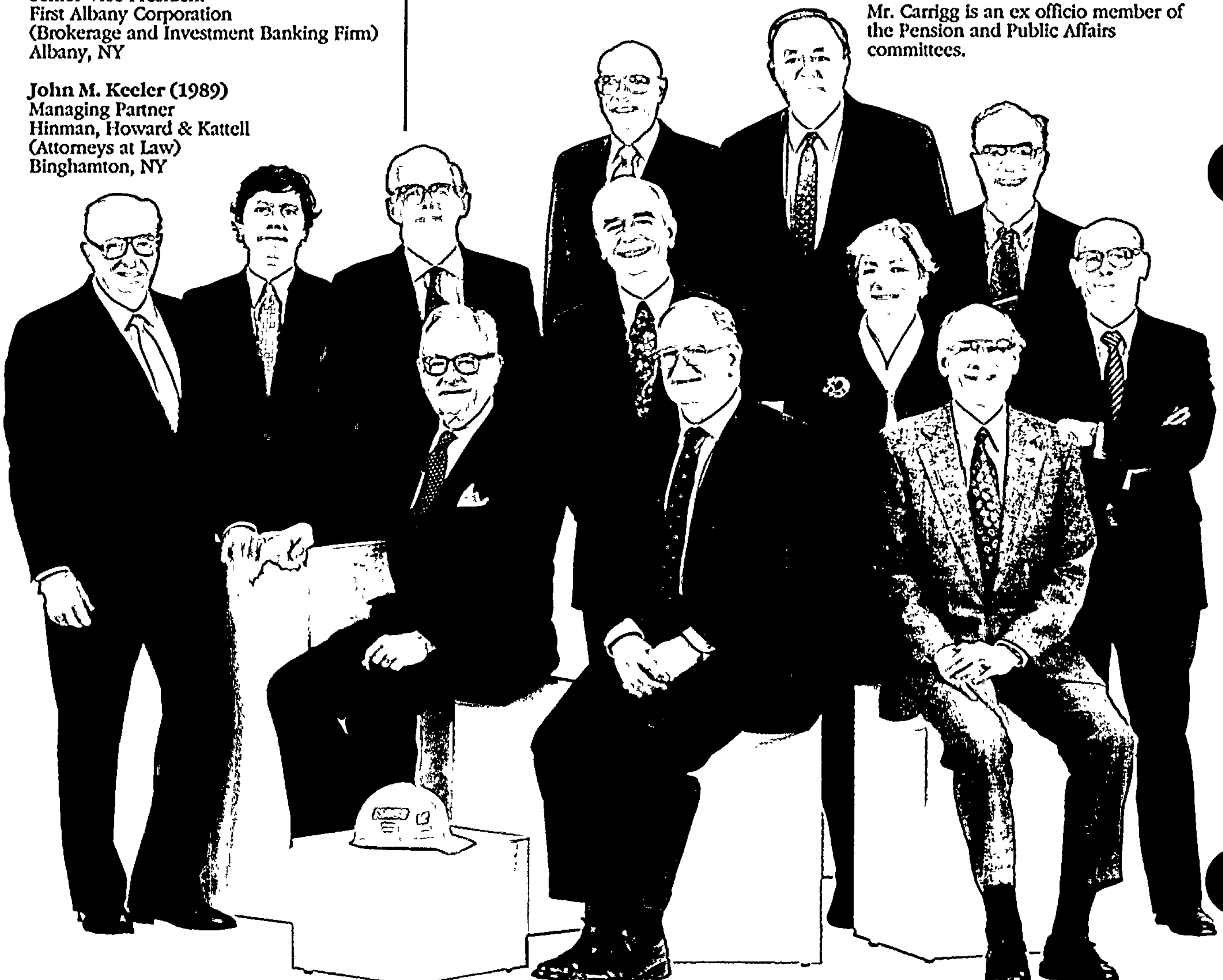
C. William Stuart (1971)
Chairman and Chief Executive Officer
C.W. Stuart & Co., Inc.
(Interstate Trucking Concern)
Newark, NY

COMMITTEES OF THE BOARD

Chairperson listed first

Audit: Plane, Gioia, Keeler, Lynch
Executive and Finance: Allen, Carrigg, Gilmour, Kintigh, Marshall, Newcomb, Stuart
Executive Compensation and Succession: Gilmour, Allen, Casarett, Lynch, Marshall, Newcomb
Pension: Keeler, Kintigh, Plane, Stuart
Public Affairs: Casarett, Gioia, Keeler, Lynch

Mr. Carrigg is an ex officio member of the Pension and Public Affairs committees.



Seated, from left: Robert A. Plane, David R. Newcomb and John M. Keeler.
Standing, from left: Everett A. Gilmour, Paul L. Gioia, Alton G. Marshall, Allen E. Kintigh, James A. Carrigg, Ben E. Lynch, Alison P. Casarett, C. William Stuart and Wells P. Allen, Jr.

OFFICERS

Ages and years of service as of December 31, 1992 in parentheses

James A. Carrigg (59, 34)
Chairman, President and Chief Executive Officer

Ralph R. Tedesco (39, 14)
Executive Assistant to the Chairman, President and Chief Executive Officer

Patricia A. Orzell (50, 31)
Assistant Secretary

ELECTRIC BUSINESS UNIT

Jack H. Roskoz (54, 30)
Senior Vice President

John J. Bodkin (47, 24)
Vice President - Electric Transmission and Distribution

William G. McCann (45, 23)
Vice President - West Region Electric Operations

Gerald E. Putman (42, 22)
Vice President - East Region Electric Operations

Vincent W. Rider (61, 34)
Vice President - Electric Generation

Irene M. Stillings (53, 16)
Vice President - Electric Marketing

Michael J. Turkovic (60, 37)
Vice President - Purchasing and Administration

Denis E. Wickham (43, 20)
Vice President - Electric Resource Planning

John I. Fiala (56, 34)
Assistant Vice President - Plant Operations

John V. Kutz (58, 36)
Assistant Vice President - Transmission and Distribution Operations

GAS BUSINESS UNIT

Russell Fleming Jr. (54, 2)
Senior Vice President

Charles E. Dickson (54, 32)
Vice President - Regional Gas Operations

Robert A. Paglia (55, 27)
Vice President - Gas Marketing and Sales

MANAGEMENT SERVICES BUSINESS UNIT

Richard P. Fagan (51, 21)
Senior Vice President

Daniel W. Farley (37, 11)
Vice President and Secretary

Carl E. Johnson (50, 26)
Vice President - Consumer Services and Communications

Richard W. Page (57, 34)
Vice President - Human Resources

Sherwood J. Rafferty (45, 12)
Vice President and Treasurer (Chief Financial Officer)

Everett A. Robinson (49, 19)
Vice President and Controller (Chief Accounting Officer)

John D. Scott (54, 29)
Vice President - Economics

Roy Hogben (53, 35)
Assistant Controller

James M. Niefer (62, 37)
Assistant Secretary

Robert T. Pochily (43, 21)
Assistant Treasurer

Gary J. Turton (45, 20)
Assistant Controller

STRATEGIC MANAGEMENT BUSINESS UNIT

Paul Komar (54, 23)
Senior Vice President

MANAGEMENT CHANGES

- Dolores R. Hix, former assistant secretary and assistant to the chairman, president and chief executive officer, passed away on September 8. The Board of Directors elected Patricia A. Orzell, executive secretary to the chairman, president and chief executive officer, to the position of assistant secretary on May 14.

- Bernard M. Rider, senior vice president - strategic growth business unit, retired effective January 1, 1993.

- James A. Ackerman, vice president - East Region electric operations, is on disability leave. The Board of Directors elected Gerald E. Putman, executive assistant to the chairman, president and chief executive officer, to succeed Mr. Ackerman and Ralph R. Tedesco, manager - corporate performance, to succeed Mr. Putman.

FINANCIAL SECTION➤

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

	1992	1991	1990	1992 over 1991 Change	1991 over 1990 Change
	(Thousands, Except Per Share Amounts)				
Operating revenues	$1,691,689	$1,555,815	$1,496,780	9%	4%
Earnings available for common stock	$162,973	$148,313	$145,351	10%	2%
Average shares outstanding	67,972	62,906	58,678	8%	7%
Earnings per share	$2.40	$2.36	$2.48	2%	(5%)
Dividends per share	$2.14	$2.10	$2.06	2%	2%

The Company had operating revenues of approximately $1.7 billion in 1992, $1.6 billion in 1991, and $1.5 billion in 1990. Operating revenues increased $136 million, or 9%, in 1992, compared to 1991, primarily because of higher purchase costs of non-utility generation which are passed on to customers, and new electric and natural gas rates which became effective in February 1991 and August 1992. In addition, higher electric and natural gas retail sales due to an increase in retail customers, colder weather, and the April 1991 acquisition of Columbia Gas of New York, Inc. (CNY) helped boost operating revenues for 1992. In 1991, operating revenues rose $59 million, or 4%, compared to 1990, primarily because of an increase in electric and natural gas rates effective February 1991 and the April 1991 acquisition of CNY.

Earnings per share increased 4 cents, or 2%, in 1992 compared to 1991, while earnings per share decreased 12 cents, or 5%, in 1991 compared to 1990. Earnings per share in 1992 were favorably affected by the growth in electric and natural gas retail sales primarily due to an increase in retail customers, colder weather, and the April 1991 acquisition of CNY. The Company's efforts to control costs also contributed to the increase in 1992 earnings per share. Earnings per share were limited by a six-month electric rate moratorium that began in February 1992. In 1991, earnings per share decreased primarily because of the reduction in our allowed return on equity from 13% in 1990 to 11.7% effective February 1991. In addition, lower electric and natural gas retail sales, which resulted from warmer weather and the weak economy, also decreased earnings. Incentives earned on demand-side management (DSM) programs, however, had a favorable effect on 1991 earnings per share.

Average shares outstanding were 67,972,000 in 1992, 62,906,000 in 1991, and 58,678,000 in 1990. Average shares outstanding increased 8% in 1992 compared to 1991 due to the issuance of 5 million shares of common stock in March 1992, and the issuance of 1,039,000 shares of common stock through the Dividend Reinvestment and Stock Purchase Plan (Plan). In 1991, average shares outstanding increased 7% because of the issuance of 4 million shares of common stock in October 1990, and the issuance of 970,000 shares of common stock issued through the Plan.

Interest Expense

Interest expense decreased 5% in 1992 and 6% in 1991 (before the reduction for allowance for borrowed funds used during construction). Interest on long-term debt decreased in 1992 and 1991 mainly due to the refinancing of certain high-coupon long-term debt at lower interest rates. In 1992 and 1991, interest expense also declined due to a decrease in the average amount of commercial paper outstanding and lower interest rates on the Company's variable rate debt. (See Liquidity and Capital Resources - Financing Activities).

Operating Results by Business Unit

Electric	1992	1991	1990	1992 over 1991 Change	1991 over 1990 Change
	(Thousands)				
Retail sales-kilowatt-hours (kwh)	13,294,466	13,107,115	13,197,673	1%	(1%)
Operating revenues	$1,451,525	$1,367,936	$1,334,509	6%	3%
Operating expenses	$1,146,619	$1,056,969	$1,021,669	8%	3%

The 1% growth in electric retail sales in 1992 compared to 1991 was the result of colder weather and an increase in customers. Retail sales decreased 1% in 1991 compared to 1990 mainly due to warmer weather and the weak economy.

Electric operating revenues increased $84 million, or 6%, in 1992 compared to 1991. This reflects the increases in electric rates which became effective February 1991 and August 1992. It also reflects the higher non-utility generation purchase costs and an increase in certain New York State gross receipts taxes, both of which are passed on to customers. Also, the 1% increase in electric retail sales, due to colder weather and an increase in customers, boosted revenues. Electric operating revenues increased $33 million, or 3%, in 1991 compared to 1990, despite a 1% decrease in electric retail sales. This increase is primarily because of the increase in rates effective February 1991 and an increase in certain New York State gross receipts taxes which are passed on to customers.

Electric operating expenses increased $90 million, or 8%, in 1992 compared to 1991, while operating expenses increased $35 million, or 3%, in 1991 compared to 1990. In 1992, expenses increased primarily because of higher non-utility generation purchase costs and certain New York State gross receipts taxes, both of which are passed on to customers. Operating expenses also increased because of higher DSM program costs and an increase in federal income taxes resulting from higher pretax book income. However, a decrease in maintenance expense reduced the increase in operating expenses. In 1991, electric operating expenses rose 3% primarily because of higher gross receipts taxes and higher federal income taxes resulting from higher pretax book income.

Natural Gas	1992	1991	1990	1992 over 1991 Change	1991 over 1990 Change
	(Thousands)				
Retail sales-dekatherms (dth)	39,357	29,874	25,515	32%	17%
Deliveries (dth)	56,366	42,404	33,672	33%	26%
Operating revenues	$240,164	$187,879	$162,271	28%	16%
Operating expenses	$221,307	$177,751	$147,278	25%	21%

Natural gas retail sales increased 32% in 1992 compared to 1991, and 17% in 1991 compared to 1990. The 1992 and 1991 increases in retail sales, along with the increase in deliveries, are largely because of the April 1991 acquisition of CNY. Excluding CNY, natural gas retail sales increased 8% in 1992, primarily because of colder weather. In 1991, natural gas retail sales decreased 7%, excluding CNY, because of warmer winter weather and the weak economy.

Natural gas operating revenues rose $52 million, or 28%, in 1992 compared to 1991, and $26 million, or 16%, in 1991 compared to 1990. Those increases are principally the result of the acquisition of CNY and the increases in rates effective February 1991 and August 1992. Also, an increase in certain gross receipts taxes, which is passed on to customers, boosted 1992 revenues.

Natural gas operating expenses increased $44 million, or 25%, in 1992 compared to 1991. This increase is primarily due to the increased quantity of natural gas purchased as a result of the CNY acquisition, and an increase in certain New York State gross receipts taxes passed on to customers. Natural gas operating expenses increased $30 million, or 21%, in 1991 compared to 1990, mainly because of the acquisition of CNY.

LIQUIDITY AND CAPITAL RESOURCES

Competitive Conditions

The utility industry is rapidly changing and moving toward a competitive environment. Factors contributing to this are: open access to electric transmission lines; Federal Energy Regulatory Commission (FERC) Order 636 which significantly affects the natural gas industry; and the National Energy Policy Act of 1992 (Energy Policy Act). In addition, the Company's desire to respond to the economic pressures on its large customers, high purchase costs of non-utility generation, rising health care costs, increasing taxes, weak economic conditions, conservation programs, and compliance with environmental laws and regulations are factors that are placing increased pressure on our electric and natural gas rates.

The Company's five-year strategic plan addresses the competitive, rapidly changing utility industry. The plan positions us to meet the challenges of the future. The Company's objective is to remain competitive in its core businesses in the face of increased competition and continued deregulation. Diversification, whether in the regulated or nonregulated arena, will play an important role in the Company's future. While the strength of the Company's core electric and natural gas businesses remains our focus, and while we will not compromise the Company's financial integrity, we are actively evaluating a number of corporate development opportunities for investment.

In April 1992, the Public Service Commission of the State of New York (PSC) issued an order allowing the Company to invest up to 5% of its consolidated capitalization (approximately $180 million at December 31, 1992) in one or more subsidiaries that may engage or invest in energy-related or environmental services businesses and provide related services. At December 31, 1992, the Company had not invested in any such businesses.

In April 1992, the FERC issued Order 636 which requires interstate natural gas pipeline companies to offer customers unbundled or separate services. With the unbundling of services, primary responsibility for reliable natural gas supply will shift from interstate pipeline companies to local distribution companies, such as the Company. This should result in increased direct access to low cost natural gas supplies by local distribution companies and end users. One goal of Order 636 is to provide equitable access to interstate pipeline capacity. FERC Order 636 will substantially restructure the interstate natural gas market and intensify competition within the natural gas industry. Order 636 will allow us, subject to PSC approval, to restructure rates and provide multiple service options to our customers.

The Energy Policy Act was enacted in October 1992, and will bring major changes to the utility industry. Certain provisions of the Energy Policy Act amended the Public Utility Holding Company Act of 1935 (PUHCA). These amendments will encourage greater competition by establishing a new category of wholesale electric generators which are exempt from PUHCA. The Energy Policy Act also enables the FERC to order utilities to provide open access to transmission systems. The alternative fuel titles of the Act should serve to promote the use of natural gas and electric vehicles.

Recent Accounting Standards

The Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106) in December 1990. SFAS 106 requires that the Company accrue a liability for estimated future postretirement benefits during an employee's working career rather than recognize an expense when benefits are paid. SFAS 106 is effective for fiscal years beginning after December 15, 1992.

The Company adopted SFAS 106 in January 1993. At the time of adoption, the accumulated benefit obligation was $225 million. The Company plans to recognize the accumulated benefit obligation over 20 years in accordance with SFAS 106. Adoption of the new standard is expected to increase annual expenses, before deferral for ratemaking purposes, by about $32 million, or 7 times the 1992 expense.

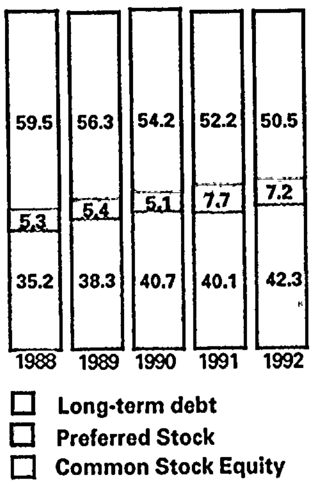
In March 1992, the PSC issued a draft Statement of Policy concerning the accounting and ratemaking treatment for postretirement benefit costs. This draft policy provides for, among other things, recovery in rates for deferred SFAS 106 costs. In addition, the draft policy proposes that deferred SFAS 106 costs will be recovered in rates within 10 years of the adoption of SFAS 106. The Statement of Policy is expected to be approved by the PSC during the spring of 1993. In addition, the July 1992 rate decision allows the Company to recover a portion of SFAS 106 costs in revenues from its customers and to defer the remainder of these costs for recovery in accordance with the draft Statement of Policy. The Company anticipates that future SFAS 106 costs will be recoverable through rates.

In November 1992, the FASB issued Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits (SFAS 112), which is effective for fiscal years beginning after December 15, 1993. SFAS 112 will require the Company to recognize the obligation to provide postemployment benefits to former or inactive employees after employment but before retirement. The Company is evaluating the impact of SFAS 112 and intends to adopt it in 1994.

Financing Activities

The Company remains committed to improving its financial integrity. We believe this commitment will take on added significance as competition heightens in the industry.

Capital Structure



In March 1992, the Company sold 5 million shares of common stock at $27.25 a share. After deducting underwriting fees, net proceeds of $26.54 per share, or $132.7 million, were used to repay commercial paper. The sale increased the Company's common stock equity ratio in March 1992 to over 43%, the highest level since we became an independent utility in 1949.

The common equity ratio also improved in 1992 as a result of the Dividend Reinvestment and Stock Purchase Plan (Plan) and retained earnings. We received $30.3 million from the issuance of 1,039,159 shares of common stock through the Plan and retained earnings increased by $18.3 million during 1992.

Common stock dividends paid in 1992 increased 9.7% over 1991 reflecting the increase in common stock outstanding and an increase in the dividend paid from $2.10 to $2.14 per share.

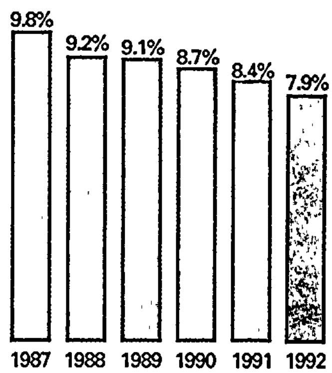
In February 1992, we redeemed, at par, through a sinking fund provision in our mortgage, the remaining $20.4 million of 10⅝% Series first mortgage bonds due 2016.

In October 1992, we issued $150 million of 6¾% Series first mortgage bonds due 2002. Net proceeds from the sale were used in connection with the redemption, at a premium, in October 1992 of $145.1 million of first mortgage bonds: $31.1 million of the 9.35% Series due 2003; $75 million of the 9⅜% Series due 2005; and $39 million of the 9⅜% Series due 2006.

In December 1992, we issued $100 million of 8.30% Series first mortgage bonds due 2022. Net proceeds from the sale were used in connection with the redemption of $100 million of 10⅝% Series first mortgage bonds due 2018. In January 1993, $77.5 million of those 10⅝% bonds were redeemed, at a premium, and the remaining $22.5 million were redeemed, at par, in February 1993 through a sinking fund provision in our mortgage.

The refinancings will save approximately $3.2 million in annual interest costs. Our embedded cost of long-term debt was reduced to 7.9% at the end of 1992 from 9.8% in 1987 and was further reduced to 7.7% in early 1993 after the redemption of $100 million of 10⅝% Series first mortgage bonds due 2018. Unless interest rates fall further, it will be difficult to improve from the 7.7% level; however, all opportunities will be aggressively pursued.

Embedded Cost of Long-Term Debt



In February 1993, the Company plans to price $100 million of tax-exempt pollution control bonds. Net proceeds from the sale, which will be delivered in April 1994, will be used to redeem, at a premium, $60 million of 12% pollution control bonds and $40 million of 12.30% pollution control bonds.

The Company uses interim financing in the form of short-term unsecured notes, usually commercial paper, to finance certain refundings and construction expenditures, and for other corporate purposes. This provides flexibility in the timing and amounts of long-term financings. We had $64 million of commercial paper outstanding at December 31, 1992, at a weighted average interest rate of 4.0%. The weighted average interest rate during 1992 was 4.3%.

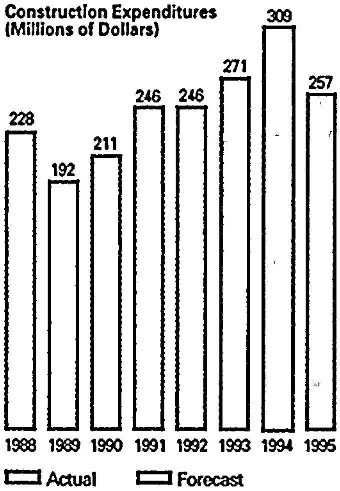
We also have a revolving credit agreement with certain banks which provides for borrowing up to $200 million to July 31, 1995. The Company did not have any outstanding loans under this agreement during 1992.

The Company's first mortgage bonds and preferred stock were upgraded by Fitch Investors Services, Inc. in July 1992. Fitch stated that the higher ratings reflect significantly improved financial protection measures since 1987. Fitch also noted our efforts in lowering our embedded cost of long-term debt during the past several years.

Moody's Investors Service upgraded our first mortgage bonds and unsecured pollution control bonds in August 1992. This upgrade was based on improvements in our financial, operating, and regulatory profile, as well as the likelihood that our financial condition will continue to improve.

Capital Expenditures

The Company's 1992 construction program totaled approximately $246 million. Most of the expenditures were for the extension of service and for improvements at existing facilities.



Construction expenditures for 1993-1995 will be primarily for the extension of service, improvements at existing facilities, and compliance with the Clean Air Act Amendments of 1990 (See Environmental Matters). The Company has no need for additional large base-load generating capacity. We forecast that our current reserve margin, coupled with more efficient use of energy (See Conservation Programs) and generation from non-utility generators (NUGs) will eliminate the need for additional generating capacity until well into the first decade of the 21st century.

The Company has on line and under contract 347 megawatts (mw) of NUG power. In addition, another 257 mw of NUG power is under construction. We are required to make payments under these contracts only for the power we receive. During 1992, 1991, and 1990, the Company purchased approximately $71 million, $30 million, and $8 million of NUG power. We estimate that we will purchase approximately $151 million, $251 million, and $287 million of NUG power for the years 1993, 1994, and 1995. The requirement to purchase NUG power is expected to be a major contributor to rate increases over the next 3 years, and is expected to increase rates by approximately 8% during this time period.

In June 1992, the Company entered into an agreement with Indeck Energy Services of Kirkwood, Inc., Indeck Energy Services, Inc., and Indeck Kirkwood Limited Partnership to terminate the power purchase agreement for the 55 mw Indeck-Kirkwood project. The termination agreement will save customers an estimated $350 million over 20 years. In January 1993, the PSC approved full recovery of the $11.5 million in termination costs in rates.

In December 1992, the Company entered into an agreement with Kamine/Besicorp Corning L.P., Kamine South Corning Cogen Co., Inc., and Beta South Corning, Inc. to terminate the power purchase agreement for the 79 mw South Corning cogeneration project. The termination agreement will save customers an estimated $300 million over 25 years. The Company plans to petition the PSC in early 1993 to recover $34 million in termination costs in rates. Terminating these agreements is part of our continuing effort to minimize future rate increases associated with uneconomical power purchases from NUGs.

As a result of the PSC's competitive bidding program, the Company is contracting for 25 mw in conservation projects to be available by November 1994. In accordance with a PSC ruling issued in October 1992, the Company will conduct an auction for an additional 10 mw of conservation projects. The timing of the auction has not yet been determined, but the Company does not expect that those conservation projects will be available before 1995. We expect to recover the costs associated with these contracts from our customers. The Company will utilize various methods, including competitive bidding, to minimize the economic impacts on customers of adding new resources to our system, while maintaining our current level of system reliability.

The following table provides information on the Company's estimated sources and uses of funds for 1993-1995. This forecast is subject to periodic review and revision, and actual construction costs may vary because of revised load estimates, imposition of additional regulatory requirements, and the availability and cost of capital.

	1993	1994	1995	Total
		(Millions)		
Sources of funds				
Internal funds	$251	$259	$262	$ 772
Sale of accounts receivable	14	–	–	14
Long-term financing				
Debt and stock proceeds	140	238	43	421
Debt proceeds held in trust	(56)	48	8	–
Net financing proceeds	84	286	51	421
Increase (decrease) in short-term debt	91	27	(2)	116
Total	$440	$572	$311	$1323
Uses of funds				
Construction				
Cash expenditures	$261	$296	$248	$ 805
AFDC	10	13	9	32
Total construction	271	309	257	837
Retirement of securities and sinking fund obligations	111	227	24	362
Working capital and deferrals	37	12	4	53
Demand-side management program costs (net)	21	24	26	71
Total	$440	$572	$311	$1323

As shown in the preceding table, internal sources of funds represent 92% of construction expenditures for 1993-1995, or approximately 77% after adjusting for working capital and deferrals and net demand-side management (DSM) program costs.

Conservation Programs

The Company has implemented a number of DSM programs. In 1990, we received approval from the PSC for a plan to obtain earnings incentives for conducting efficient DSM programs. Those incentives are currently limited to a .75% return on equity (approximately $16.1 million, before taxes, at December 31, 1992) allocated to electric operations. The incentives are based on savings from 20 large-scale programs including financial and technical assistance to various customers.

In 1992, our customers saved approximately 139.6 million kilowatt-hours (kwh) on an annualized basis through our DSM programs. The implementation of these programs cost $40 million in 1992 and will cost approximately $34 million in 1993 with estimated customer savings of 158 million kwh on an annualized basis, thus producing more savings with less cost. We filed a two-year (1993-1994) conservation plan with the PSC in June 1992, seeking approval to continue implementation of those programs which have demonstrated cost effectiveness. Marginal or high unit-cost programs will be eliminated and the remaining DSM programs will be consolidated into five new comprehensive programs which will benefit all customer classes. The Company received PSC approval for this plan in December 1992.

Environmental Matters

The Company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Compliance programs will very likely increase the cost of electric and natural gas service by requiring changes to our operations and facilities. Historically, rate recovery has been authorized for the cost incurred for compliance with environmental laws and regulations.

Due to existing and proposed legislation and regulations, and legal proceedings commenced by governmental bodies and others, the Company may also incur costs from the disposal of hazardous substances produced during our operations or those of our predecessors. We have been notified by the U.S. Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation that we are among the potentially responsible parties who may be liable to pay for costs incurred to remediate certain hazardous substances at 9 waste sites, not including our inactive gas manufacturing sites which are discussed below. With respect to the 9 sites, 1 site is included on the Federal National Priorities List, 1 site is unlisted but is the subject of an EPA administrative order, and 7 sites are included in the New York State Registry of Inactive Hazardous Waste Sites (New York State Registry). Any liability may be joint and several for certain of these sites. The ultimate cost to remediate these sites will be dependent on such factors as the remedial action plan selected, the extent of site contamination, and the portion attributed, if any, to the Company. As a result, we are unable to estimate the extent of possible remediation costs. There is no clear precedent with the PSC for rate recovery of these types of remediation costs. However, since the PSC has previously allowed us to recover similar costs in rates (e.g., investigation and clean-up costs relating to coal tar sites), we expect to recover any remediation costs that we may incur.

A number of the Company's inactive gas manufacturing sites have been listed in the New York State Registry. We have filed petitions to delist the majority of the sites. Our program to investigate and initiate remediation at our 38 known inactive gas manufacturing sites has been extended through 2000. Estimated expenditures over this time period are $25 million, which are reflected in our Consolidated Balance Sheets at December 31, 1992, to investigate and initiate remediation, as necessary, at the known gas manufacturing sites. We expect to recover such expenditures in rates, as we have previously been allowed by the PSC to recover such costs in rates.

The Clean Air Act Amendments of 1990 (1990 Amendments) will result in significant future expenditures for the reduction of sulfur dioxide, nitrogen oxides, and possibly toxic emissions at several of our coal-fired generating stations. Under the 1990 Amendments, we must reduce our annual sulfur dioxide emissions by 49% from approximately 138,000 tons in 1989 to 71,000 tons by 2000. We estimate that over a 25-year period the cost to comply with the sulfur dioxide and nitrogen oxide limitations specified in the 1990 Amendments is approximately $252 million (on a present value basis) for all capital and operating and maintenance expenses, of which $17.3 million has been incurred to date. This cost includes $159 million for an innovative flue gas desulfurization (FGD) system and a nitrogen oxide reduction system expected to be completed in 1995 at our Milliken Generating Station (Milliken).

In September 1991, we were selected by the Department of Energy (DOE) to receive federal funds for these systems. In October 1992, the DOE approved $45 million for these systems. In addition, the Company expects to receive funding totaling up to $17 million from other sources. We estimate that a 2% electric rate increase will be required for the cost of reducing sulfur dioxide and nitrogen oxides emissions for both Phase I (begins January 1, 1995) and Phase II (begins January 1, 2000).

The cost of controlling toxic emissions, if required, cannot be estimated at this time. Regulations may be adopted at the state level which would limit emissions even further, at an additional cost to the Company. We anticipate that the costs incurred to comply with the 1990 Amendments will be recoverable through rates based on previous rate recovery of required environmental costs.

The 1990 Amendments require the EPA to allocate annual emissions allowances to each of our coal-fired generating stations based on statutory emissions limits. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. During Phase I, we estimate that the Company will have allowances in excess of the affected coal-fired generating stations' actual emissions. The Company is considering various methods of using, banking, or selling these excess emissions allowances. During Phase II, we estimate that the annual tons emitted by the Company's coal-fired generating stations will equal our annual emissions allowances.

In addition to the annual emissions allowances allocated to the Company by the EPA, we may obtain extension reserve allowances that the EPA will issue to companies electing to build scrubbers in Phase I such as the FGD system at Milliken. Due to the uncertainty of how many extension reserve allowances will be demanded, the extent to which the demand may exceed the supply, and the method of allocating extension reserve allowances, the Company entered into a pooling agreement with other utilities which are eligible to receive some of the extension reserve allowances. This agreement provides assurance that the Company will receive some of the extension reserve allowances in the event that demand exceeds supply.

Regulatory Matters

In July 1992, the PSC approved an electric rate increase of $63.9 million annually, or 5%, and a natural gas rate increase of $10.4 million annually, or 4.1%, effective August 1, 1992. The electric rate increase included approximately $16 million of capacity charges associated with the cost of purchasing electricity from NUGs. In the event the capacity component of purchasing electricity from NUGs falls below or exceeds $16 million, the difference will be deferred and passed on to customers in a future rate year. The rate decision provided for an 11.2% return on common equity and an overall rate of return of 9.7%.

The rate decision allowed the Company to recognize on its income statement, beginning August 1992, electric and natural gas unbilled revenues on a full accrual basis. This recognition did not materially affect annual revenues and earnings for common stock in 1992 and is not expected to do so in 1993, but will affect the recognition of revenues from quarter to quarter, on a comparative basis.

In July 1992, the Company entered into discussions with the PSC staff and other interested parties in an attempt to develop a multi-year rate plan that addresses costs and associated rate changes. The Company continues to work with the PSC staff and other parties to reach a multi-year rate settlement.

In August 1992, the Company had planned to file with the PSC for electric and natural gas rate increases to be effective in August 1993. However, since the Company was working with the PSC staff and other parties to reach a multi-year rate settlement, the filing was delayed until November 1992. In November 1992, the Company filed for an electric rate increase of $77.5 million annually, or 5.5%, and a natural gas rate increase of $9.5 million annually, or 3.6%, to be effective August 1993. The rate filing provides for an 11.4% return on common equity and an overall rate of return of 9.6%. We cannot predict the outcome of this proceeding.

On May 14, 1991, the PSC issued an order approving an agreement between the Company and the PSC staff which settled a fuel-procurement proceeding instituted by the PSC. The agreement, among other things, provided for a six-month electric rate moratorium beginning on February 1, 1992. Earnings for common stock decreased approximately $16 million in 1992 as a result of the rate moratorium.

Federal Energy Regulatory Commission (FERC) Proceeding

In August 1991 and October 1992, the FERC issued orders which revised its generic policy related to filing requirements for contracts determined to be subject to its jurisdiction under the Federal Power Act. Under the revised policy, FERC may require a utility to refund certain revenues collected under late-filed contracts.

In December 1992, FERC issued a notice requesting comments from interested parties relating to its filing requirements for contracts. The notice solicited comments on whether the obligation to file jurisdictional agreements should extend to certain terminated agreements as well as existing agreements. The Company and many other utilities filed comments in January 1993 challenging the filing requirements and the appropriateness of the refund obligations.

The Company continues to review its compliance with FERC contract filing requirements. In October 1992, the Company determined that it may be required to file at least four additional contracts with FERC. The Company is unable to predict what actions FERC may take as a result of its notice and is unable to estimate the amount and timing of refunds, if any, that may be required. Therefore, the Company cannot predict the ultimate disposition of this matter, but believes that it will not have a material adverse effect on its financial position.

CONSOLIDATED STATEMENTS OF INCOME

Ended December 31	1992	1991	1990
	(Thousands, except Per Share Amounts)		
OPERATING REVENUES			
Electric	$1,451,525	$1,367,936	$1,334,509
Natural gas	240,164	187,879	162,271
TOTAL OPERATING REVENUES	1,691,689	1,555,815	1,496,780
OPERATING EXPENSES			
Fuel used in electric generation	262,531	274,877	274,245
Electricity purchased	95,026	45,808	34,613
Natural gas purchased	126,815	99,528	88,589
Other operating expenses	318,680	279,364	268,829
Maintenance	102,500	110,131	106,665
Depreciation and amortization (Note 1)	158,977	152,380	147,659
Federal income taxes (Notes 1 and 2)	102,456	94,447	89,577
Other taxes (Note 11)	200,941	178,185	158,770
TOTAL OPERATING EXPENSES	1,367,926	1,234,720	1,168,947
OPERATING INCOME	323,763	321,095	327,833
OTHER INCOME AND DEDUCTIONS	12,036	6,076	(1,508)
INCOME BEFORE INTEREST CHARGES	335,799	327,171	326,325
INTEREST CHARGES			
Interest on long-term debt	145,822	151,649	158,209
Other interest	9,566	11,877	15,181
AFDC - borrowed (Note 1)	(3,557)	(4,998)	(5,078)
INTEREST CHARGES-NET	151,831	158,528	168,312
T INCOME	183,968	168,643	158,013
FERRED STOCK DIVIDENDS	20,995	20,330	12,662
ARNINGS AVAILABLE FOR COMMON STOCK	$162,973	$148,313	$145,351
EARNINGS PER SHARE	$2.40	$2.36	$2.48
AVERAGE SHARES OUTSTANDING	67,972	62,906	58,678

The notes on pages 30 through 41 are an integral part of the financial statements.

AFDC is allowance for funds used during construction.

CONSOLIDATED BALANCE SHEETS

December 31	1992	19[illegible]
	(Thousands)	
ASSETS		
UTILITY PLANT, AT ORIGINAL COST (NOTE 1)		
Electric (Note 8)	$4,573,444	$4,421,839
Natural gas	352,059	317,694
Common	157,979	156,342
	5,083,482	4,895,875
Less accumulated depreciation	1,427,793	1,309,829
NET UTILITY PLANT IN SERVICE	3,655,689	3,586,046
Construction work in progress	177,566	166,815
TOTAL UTILITY PLANT	3,833,255	3,752,861
OTHER PROPERTY AND INVESTMENTS	59,157	56,581
CURRENT ASSETS		
Cash and cash equivalents (Notes 1 and 6)	3,968	18,601
Special deposits (Note 6)	96,432	11,463
Accounts receivable, net (Note 1)	171,683	133,338
Fuel, at average cost	69,077	66,602
Materials and supplies, at average cost	50,637	51,736
Prepayments	37,897	37,019
Accumulated deferred federal income tax benefits (Notes 1 and 2)	15,437	16,278
Unfunded future federal income taxes (Notes 1 and 2)	20,880	22,659
TOTAL CURRENT ASSETS	466,011	35[illegible]
DEFERRED CHARGES (NOTE 1)		
Accumulated deferred federal income tax benefits (Notes 1 and 2)	84,257	83,718
Unfunded future federal income taxes (Notes 1 and 2)	372,840	413,586
Unamortized debt expense	96,378	91,850
Other	264,530	168,544
TOTAL DEFERRED CHARGES	818,005	757,698
TOTAL ASSETS	$5,176,428	$4,924,836

The notes on pages 30 through 41 are an integral part of the financial statements.

CONSOLIDATED BALANCE SHEETS

December 31	1992	1991
	(Thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock equity		
Common stock ($6.66⅔ par value, 90,000,000 and 80,000,000 shares authorized and 69,439,397 and 63,400,238 shares issued and outstanding at December 31, 1992 and 1991, respectively)	$462,929	$422,668
Capital in excess of par value	796,505	673,791
Retained earnings	327,040	308,688
Total common stock equity	1,586,474	1,405,147
Preferred stock redeemable solely at the option of the Company (Note 4)	160,500	160,500
Preferred stock subject to mandatory redemption requirements (Notes 4 and 6)	106,900	108,550
Long-term debt (Notes 3 and 6)	1,777,027	1,788,915
TOTAL CAPITALIZATION	3,630,901	3,463,112
CURRENT LIABILITIES		
Current portion of long-term debt and preferred stock (Notes 3 and 4)	115,659	38,653
Commercial paper (Notes 5 and 6)	64,100	103,900
Accounts payable and accrued liabilities	95,996	100,847
Interest accrued (Note 6)	37,690	43,440
Unfunded future federal income taxes (Notes 1 and 2)	20,880	22,659
Accumulated deferred federal income taxes (Notes 1 and 2)	24,083	16,747
Other	67,499	75,483
TOTAL CURRENT LIABILITIES	425,907	401,729
DEFERRED CREDITS		
Accumulated deferred investment tax credits (Notes 1 and 2)	141,729	148,078
Excess deferred federal income taxes (Notes 1 and 2)	55,762	63,778
Other	107,160	67,961
TOTAL DEFERRED CREDITS	304,651	279,817
ACCUMULATED DEFERRED FEDERAL INCOME TAX (NOTES 1 AND 2)		
Unfunded future federal income taxes	372,840	413,586
Other	417,129	366,592
TOTAL ACCUMULATED DEFERRED FEDERAL INCOME TAXES	789,969	780,178
COMMITMENTS AND CONTINGENCIES (NOTE 9)	25,000	–
TOTAL CAPITALIZATION AND LIABILITIES	$5,176,428	$4,924,836

The notes on pages 30 through 41 are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31	1992	1991	19[illegible]
		(Thousands)	
OPERATING ACTIVITIES			
Net Income	$183,968	$168,643	$158,013
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	158,977	152,380	147,659
Deferred fuel and purchased gas	(14,645)	2,507	(6,225)
Federal income taxes and investment tax credits deferred - net	50,683	53,105	50,924
Recovered (deferred) transmission wheeling charges	–	(861)	20,793
Unbilled revenue recognition (Note 1)	(22,228)	(40,147)	(43,849)
Demand-side management program costs	(22,863)	(15,118)	(2,051)
Other - net	(13,022)	3,832	11,103
Changes in certain current assets and liabilities, net of effects from the purchase of Columbia Gas of New York, Inc. in 1991:			
Special deposits	(1,873)	(4,108)	(443)
Accounts receivable	(11,936)	(15,541)	(11,123)
Prepayments	(878)	(7,882)	(2,650)
Inventory	(1,417)	4,590	(37,874)
Accounts payable and accrued liabilities	(8,287)	5,656	11,670
Interest accrued	(5,750)	(3,610)	(4,486)
Other - net	(4,462)	2,440	(5,420)
NET CASH PROVIDED BY OPERATING ACTIVITIES	286,267	305,886	286,041
INVESTING ACTIVITIES			
Utility plant construction expenditures, net of AFDC - other (Note 1)	(243,051)	(244,037)	(210,540)
Payment for purchase of Columbia Gas of New York, Inc., net of cash acquired	–	(57,096)	–
NET CASH USED IN INVESTING ACTIVITIES	(243,051)	(301,133)	(210[illegible]
FINANCING ACTIVITIES			
Issuance of first mortgage bonds	247,668	147,243	294,316
Sale of common stock	162,965	25,380	115,089
Sale of preferred stock	–	98,975	–
First mortgage bonds and preferred stock repayments	(178,289)	(142,715)	(296,289)
Special deposit - first mortgage bond repayments	(83,096)	–	(498)
Long-term notes repayment	(1,593)	(2,322)	(5,078)
Commercial paper - net	(39,800)	30,675	(47,775)
Dividends on common and preferred stock	(165,704)	(150,106)	(133,906)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(57,849)	7,130	(74,141)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(14,633)	11,883	1,360
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	18,601	6,718	5,358
CASH AND CASH EQUIVALENTS, END OF YEAR (NOTES 1 AND 6)	$3,968	$18,601	$6,718
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid during the period:			
Interest, net of amounts capitalized	$149,299	$159,927	$171,675
Income taxes	$38,477	$31,790	$33,111
SUPPLEMENTAL DISCLOSURE OF NONCASH INVESTING AND FINANCING ACTIVITIES			
Capital lease additions	$2,970	$9,524	$12,192
The Company purchased all of the common stock of Columbia Gas of New York, Inc. In conjunction with the acquisition, liabilities were assumed as follows:			
Fair value of assets acquired	–	$81,982	–
Cash paid	–	(57,096)	–
Liabilities assumed	–	$24,886	[illegible]

The notes on pages 30 through 41 are an integral part of the financial statements.

AFDC is allowance for funds used during construction.

CONSOLIDATED STATEMENTS OF CHANGES COMMON STOCK EQUITY

(Thousands, except Shares and Per Share Amounts)

	Common Stock $6.66 2/3 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Total
BALANCE, JANUARY 1, 1990	57,553,528	$383,690	$573,293	$268,201	$1,225,184
Net income				158,013	158,013
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,484)	(11,484)
- mandatory				(1,178)	(1,178)
Common stock ($2.06 per share)				(121,302)	(121,302)
Issuance of stock:					
Public Offering	4,000,000	26,667	66,990		93,657
Dividend reinvestment and stock purchase plan	876,769	5,845	15,609		21,454
BALANCE, DECEMBER 31, 1990	62,430,297	416,202	655,892	292,250	1,364,344
Net income				168,643	168,643
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,395)	(11,395)
- mandatory				(8,935)	(8,935)
Common stock ($2.10 per share)				(131,875)	(131,875)
Issuance of stock:					
Dividend reinvestment and stock purchase plan	969,941	6,466	17,899		24,365
NCE, DECEMBER 31, 1991	63,400,238	422,668	673,791	308,688	1,405,147
t income				183,968	183,968
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,164)	(11,164)
- mandatory				(9,831)	(9,831)
Common stock ($2.14 per share)				(144,621)	(144,621)
Issuance of stock:					
Public Offering	5,000,000	33,333	99,367		132,700
Dividend reinvestment and stock purchase plan	1,039,159	6,928	23,347		30,275
BALANCE, DECEMBER 31, 1992	69,439,397	$462,929	$796,505	$327,040	$1,586,474

The notes on pages 30 through 41 are an integral part of the financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the Company's wholly-owned subsidiary, Somerset Railroad Corporation (SRC). All significant intercompany balances and transactions are eliminated in consolidation.

Utility plant

The cost of repairs and minor replacements is charged to appropriate operating expense accounts. The cost of renewals and betterments, including indirect cost, is capitalized. The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation.

Depreciation and amortization

Depreciation expense is determined using straight-line rates, based on the average service lives of groups of depreciable property in service. Depreciation accruals were equivalent to 3.3% of average depreciable property for 1992, 1991, and 1990. Depreciation expense includes the amortization of certain deferred charges authorized by the Public Service Commission of the State of New York (PSC).

Allowance for funds used during construction (AFDC)

AFDC represents the cost of funds used to finance the construction of utility plant. Those costs are capitalized during the construction period and recorded in construction work-in-progress. AFDC is recovered over the life of the plant through depreciation when the construction project is placed in service. Those costs are also credited on the income statement during the construction period as an allowance for borrowed funds used during construction, which reduces the net interest charges, and as an allowance for other (i.e., equity) funds used during construction, which is included in other income.

Revenue

In 1988, the Company began accruing electric and natural gas revenues on its balance sheet for energy provided but not yet billed. During 1992, 1991, and 1990, the Company recognized approximately $22 million, $40 million, and $44 million, respectively, of these revenues on the income statement to minimize the rate increases for these years in accordance with various PSC rate decisions. The July 1992 rate decision allows the Company to recognize on its income statement, beginning August 1992, electric and natural gas unbilled revenues on a full accrual basis.

The Company recognizes as revenues incentives earned as the result of conducting efficient demand-side management (DSM) programs. The Company is collecting those incentives in rates within 12 to 13 months after they are recognized. During 1992, 1991, and 1990, incentives earned were $15.6 million, $12.4 million, and $2.6 million, respectively. At December 31, 1992 and 1991, approximately $9.8 and $11.3 million, respectively, of DSM incentives were accrued and included in accounts receivable.

Accounts receivable

The Company has an agreement that expires in November 1996 to sell, with limited recourse, undivided percentage interests in certain of its accounts receivable from customers. The agreement allows the Company to receive up to $152 million from the sale of such interests. At December 31, 1992 and 1991, accounts receivable on the Consolidated Balance Sheets is shown net of $138 million of interests in accounts receivable sold. All fees associated with the program are included in other income and deductions on the Consolidated Statements of Income and amounted to approximately $6.5 million, $9.3 million, and $12.5 million in 1992, 1991, and 1990, respectively. Accounts receivable on the Consolidated Balance Sheets is also shown net of an allowance for doubtful accounts which was $1.9 million and $.7 million at December 31, 1992 and 1991, respectively. Bad debt expense was $11.5 million, $10.7 million, and $8.9 million in 1992, 1991, and 1990, respectively.

Federal income taxes

The Company follows the method of accounting for income taxes prescribed by Statement of Financial Accounting Standards No. 96, Accounting for Income Taxes.

The Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109), in February 1992, and it is effective for fiscal years beginning after December 15, 1992. The Company will adopt SFAS 109 in the first quarter of 1993. The adoption of SFAS 109 will not have a material effect on the Company's results of operations or financial position because SFAS 109 does not differ materially from the Statement of Financial Accounting Standards No. 96, Accounting for Income Taxes, which the Company adopted in 1987.

The Company files a consolidated federal income tax return with SRC. Deferred income taxes are provided on all temporary differences between book and taxable income. Investment tax credits, which reduce federal income taxes currently payable, are deferred and amortized over the book lives of the applicable property. The effect of the alternative minimum tax, which increases federal income taxes currently payable and generates a tax credit available for future use, is deferred and amortized at such times as the tax credit is used on the Company's federal income tax return.

Deferred charges

The Company defers certain incurred expenses, when authorized by the PSC. Those expenses are recovered from customers in the future.

Consolidated Statements of Cash Flows

The Company considers all highly liquid investments with a maturity or put date of three months or less when acquired by the Company to be cash equivalents. These investments are included in cash and cash equivalents on the Consolidated Balance Sheets.

Reclassification

Certain amounts have been reclassified on the consolidated financial statements to conform with the 1992 presentation.

2. FEDERAL INCOME TAXES

Ended December 31	1992	1991	1990
		(Thousands)	
Charged to operations			
Current	$37,237	$22,991	$37,804
Deferred - net			
Accelerated depreciation	41,492	37,409	33,704
Unbilled revenues	160	13,644	10,167
Tax Reform Act (TRA) 1986	(2,295)	(2,284)	(3,566)
Alternative minimum tax (AMT) credit	2,123	5,557	(1,763)
Demand management	9,324	8,589	1,985
Power purchase termination agreement	6,800	–	–
Miscellaneous	(4,415)	(8,243)	697
Investment tax credit (ITC) deferred	12,030	16,784	10,549
	102,456	94,447	89,577
Included in other income			
Amortization of deferred ITC	(16,927)	(11,297)	(5,756)
Miscellaneous	3,747	(533)	176
TOTAL	$89,276	$82,617	$83,997

The Company's effective tax rate differed from the statutory rate of 34% due to the following:

Year Ended December 31	1992	1991	1990
		(Thousands)	
Tax expense at statutory rate	$92,903	$85,428	$82,283
[illegible]ciation not normalized	16,697	16,051	14,459
[illegible]986 - net	(2,485)	(2,306)	(3,566)
[illegible] amortization	(16,927)	(11,297)	(5,756)
Cost of removal	(4,079)	(6,120)	(4,148)
Other - net	3,167	861	725
TOTAL	$89,276	$82,617	$83,997

The Company has recorded unfunded future federal income taxes and a corresponding receivable from customers of approximately $393 million and $436 million as of December 31, 1992 and 1991, respectively, primarily representing the cumulative amount of federal income taxes on temporary depreciation differences which were previously flowed through to customers. Those amounts, including the tax effect of the future revenue requirements, are being amortized over the life of the related depreciable assets concurrent with their recovery in rates.

The Company has approximately $6 million of unused investment tax credits at December 31, 1992, which will begin to expire in 2001, and $12 million of AMT credits which do not expire.

3. LONG-TERM DEBT

At December 31, 1992 and 1991, long-term debt was (Thousands):

First mortgage bonds

		Amount				Amount	
Series	**Due**	**1992**	**1991**	**Series**	**Due**	**1992**	**1991**
8⅜%	Aug. 15, 1994	$100,000	$100,000	6⅞%	Dec. 1, 2006	$25,500	$25,750
8⅝%	June 1, 1996	50,000	50,000	8⅝%	Nov. 1, 2007	60,000	60,000
5⅝%	Jan. 1, 1997	25,000	25,000	10⅝%	Feb. 1, 2016	–	20,424
6¼%	Sept. 1, 1997	25,000	25,000	9¼%	Apr. 1, 2016	50,000	50,000
6½%	Sept. 1, 1998	30,000	30,000	9%	Mar. 1, 2017	100,000	100,000
7⅝%	Nov. 1, 2001	50,000	50,000	10⅝%	Jan. 1, 2018*	100,000	100,000
6¾%	Oct. 15, 2002	150,000	–	9⅞%	Feb. 1, 2020	100,000	100,000
9.35%	July 1, 2003	–	33,200	9⅞%	May 1, 2020	100,000	100,000
9⅜%	Mar. 1, 2005	–	75,000	9⅞%	Nov. 1, 2020	100,000	100,000
9⅜%	Jan. 1, 2006	3,000	45,000	8⅞%	Nov. 1, 2021	150,000	150,000
7¼%	June 1, 2006	12,000	12,000	8.30%	Dec. 15, 2022	100,000	–
Total first mortgage bonds						1,330,500	1,251,374

*$77,500,000 redeemed in January 1993 and $22,500,000 redeemed in February 1993.

Pollution control notes

Interest Rate	Maturity Date	Interest Rate Adjustment Date	Letter of Credit Expiration Date	Amount 1992	Amount 1991
12%	May 1, 2014	–	–	60,000	60,000
12.30%	July 1, 2014	–	–	40,000	40,000
3.0%	Dec. 1, 2014	Dec. 1, 1993	Dec. 15, 1994	74,000	74,000
3.25%	Mar. 1, 2015	Mar. 1, 1993	Mar. 15, 1994	37,500	37,500
2.9%	Mar. 15, 2015	Mar. 15, 1993	Mar. 31, 1994	60,000	60,000
3.10%	July 15, 2015	July 15, 1993	July 31, 1994	63,500	63,500
2.80%	Oct. 15, 2015	Oct. 15, 1993	Oct. 31, 1994	30,000	30,000
2.9%	Dec. 1, 2015	Dec. 1, 1993	Dec. 15, 1994	42,000	42,000
6.6%	July 1, 2026	July 1, 1993	July 15, 1996	65,000	65,000
5.375%	Dec. 1, 2027	Dec. 1, 1994	Dec. 15, 1994	34,000	34,000
Total pollution control notes				506,000	506,000
SRC commercial paper due December 31, 1995				27,707	29,300
Obligations under capital leases				38,804	47,260
Unamortized premium and discount on debt - net				(11,975)	(8,016)
				1,891,036	1,825,918
Less: debt due within one year - included in current liabilities				114,009	37,003
Total				$1,777,027	$1,788,915

3. LONG-TERM DEBT (Continued)

At December 31, 1992, long-term debt and capital lease payments which will become due during the next five years are:

1993	1994	1995	1996	1997
(Thousands)				
$114,009	$110,609	$36,035	$56,156	$52,196

The Company's mortgage provides for a sinking and improvement fund. This provision requires the Company to make annual cash deposits with the Trustee equivalent to 1% of the principal amount of all bonds delivered and authenticated by the Trustee prior to January 1 of that year (excluding any bonds issued on the basis of the retirement of bonds). The Company satisfied this requirement in 1992 by depositing $20.4 million in cash which was used to redeem the remaining $20.4 million of 10⅝% Series first mortgage bonds, due 2016. The Company satisfied this requirement in 1993 by depositing $22.5 million in cash which was used to redeem in February 1993, $22.5 million of [illegible]% Series first mortgage bonds, due 2018. Mandatory annual cash sinking fund requirements are $600,000 beginning June 1, 2001, for the 7¼% Series and $250,000 on December 1 in each year 1993 to 1996, for the 6⅞% Series. The amount increases to $500,000 and $750,000 on December 1, 1997 and December 1, 2002, respectively, for the 6⅞% Series.

The Company's first mortgage bond indenture constitutes a direct first mortgage lien on substantially all utility plant.

Adjustable rate pollution control notes were issued to secure like amounts of tax-exempt adjustable rate pollution control revenue bonds (Revenue Bonds) issued by a governmental authority. The Revenue Bonds bear interest at the rate indicated through the date preceding the interest rate adjustment date. The pollution control notes bear interest at the same rate as the Revenue Bonds. On the interest rate adjustment date and annually thereafter (every three years thereafter in the case of the Revenue Bonds due July 1, 2026 and December 1, 2027), the interest rate will be adjusted, not to exceed a rate of 15%, or at the option of the Company, subject to certain conditions, a fixed rate of interest, not to exceed 18%, may become effective. In the case of the Revenue Bonds due July 1, 2026 and December 1, 2027, at the option of the Company, subject to certain conditions, a fixed rate of interest may become effective prior to the interest rate adjustment date or each third year thereafter. Bond owners may elect, subject to certain conditions, to have their Revenue Bonds purchased by the Trustee.

The Company has irrevocable letters of credit which expire on the letter of credit expiration dates and which the Company anticipates being able to extend if the interest rate on the related Revenue Bonds is not converted to a fixed interest rate. Those letters of credit support certain payments required to be made on the Revenue Bonds. If the Company is unable to extend the letter of credit that is related to a particular series of Revenue Bonds, that series will have to be redeemed unless a fixed rate of interest becomes effective. Payments made under the letters of credit in connection with purchases of Revenue Bonds by the Trustee are repaid with the proceeds from the remarketing of the Revenue Bonds. To the extent the proceeds are not sufficient, the Company is required to reimburse the bank that issued the letter of credit.

4. PREFERRED STOCK

At December 31, 1992 and 1991, serial cumulative preferred stock was:

Series	Par Value Per Share	Redeemable Prior to	Redeemable Per Share	Shares Authorized and Outstanding(1)	Amount 1992	Amount 1991
					(Thousands)	
Redeemable solely at the option of the Company:						
3.75%	$100		$104.00	150,000	$15,000	$15,000
4½% (1949)	100		103.75	40,000	4,000	4,000
4.15%	100		101.00	40,000	4,000	4,000
4.40%	100		102.00	75,000	7,500	7,500
4.15% (1954)	100		102.00	50,000	5,000	5,000
6.48%	100		102.00	300,000	30,000	30,000
8.80%	100		102.00	250,000	25,000	25,000
8.48%	25	3/1/94	26.23	1,000,000	25,000	25,000
		Thereafter	25.70			
Adjustable Rate (2)	25	10/1/93	25.75	1,800,000	45,000	45,000
		Thereafter	25.00			
Total					$160,500	$160,500
Subject to mandatory redemption requirements:						
9.00% (3)	100	10/1/93	101.00	85,500	$8,550	$10,200
8.95% (4)	25	1/1/94	26.94	4,000,000	100,000	100,000
					108,550	110,200
Less: sinking fund requirements at par value – included in current liabilities					1,650	1,650
Total					$106,900	$108,550

Annual redeemable preferred stock sinking fund requirements for the next five years are:

1993	1994	1995	1996	1997
		(Thousands)		
$1,650	$1,650	$1,650	$3,600	$5,000

(1) At December 31, 1992, there were 1,550,000 shares of $100 par value preferred stock, 4,000,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

(2) The payment on the Adjustable Rate Serial Preferred Stock, Series A, for April 1, 1993 has been adjusted to an annual rate of 7.5% and subsequent payments can vary from an annual rate of 7.5% to 13.5%, based on a formula included in the Company's Certificate of Incorporation. Dividends paid from the date of issuance (1983) through the January 1, 1993 payment varied from an annual rate of 7.5% to 12.95%.

(3) On October 1, in each year 1993 through 1995, the Company must redeem 16,500 shares at par. For the years 1990 through 1992, 16,500 shares were redeemed and cancelled annually. This Series is redeemable at the option of the Company at $101.00 per share prior to October 1, 1993. The $101.00 price per share will be reduced annually by 50 cents. As of October 1, 1994, and thereafter, the redemption price will be at par. By September 30, 1996, the Company must set aside the amount required to redeem at par all remaining shares outstanding.

(4) On January 1, in each year 1997 through 2016, the Company must redeem 200,000 shares at par. This Series is redeemable at the option of the Company at $26.94 per share prior to January 1, 1994. The $26.94 price will be reduced annually by 15 cents for the years ending 1994 through 1999; by 14 cents for the year ending 2000; and by 15 cents for the years ending 2001 through 2005. The Company is restricted in its ability to redeem this Series prior to January 1, 1996.

5. BANK LOANS AND OTHER BORROWINGS

The Company has a revolving credit agreement with certain banks which provides for borrowing up to $200 million to July 31, 1995. At the option of the Company, the interest rate on borrowings is related to the prime rate, the London Interbank Offered Rate or the interest rate applicable to certain certificates of deposit. The agreement also provides for the payment of a commitment fee of .22% per annum on the unborrowed amount.

The revolving credit agreement does not require compensating balances. The Company did not have any outstanding loans under this agreement or a similar prior agreement at December 31, 1992 or 1991.

In order to provide flexibility in the timing and amounts of long-term financings, the Company uses interim financing in the form of short-term unsecured notes, usually commercial paper, to finance certain refundings and construction expenditures, and for other corporate purposes.

Information relative to short-term borrowings is as follows:

	Commercial Paper		
	1992	1991	1990
	(Thousands)		
Ending balance	$64,100	$103,900	$73,225
Maximum amount outstanding	$140,000	$111,000	$142,600
Average amount outstanding (1)	$31,400	$66,700	$98,400
Weighted average interest rate			
On ending balance	4.0%	5.3%	8.6%
During the period (2)	4.3%	6.2%	8.5%

(1) Calculated as the average of the sum of daily outstanding borrowings.
(2) Calculated by dividing total interest expense by the average of the sum of daily outstanding borrowings.

6. FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments at December 31, 1992 are as follows (Thousands):

	Carrying Amount	Fair Value
First mortgage bonds	$1,318,845	$1,388,990
Pollution control notes	$505,680	$523,251
Preferred stock subject to mandatory redemption requirements	$108,550	$119,031

The carrying amount for the following items approximates fair value because of the short maturity of those instruments: Cash and Cash Equivalents, Commercial Paper, Special Deposits, and Interest Accrued.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

First Mortgage Bonds and Pollution Control Notes

The fair value of the Company's first mortgage bonds and pollution control notes is estimated based on the quoted market prices for the same or similar issues of the same remaining maturities.

Preferred Stock

The fair value of the Company's preferred stock is estimated based on the quoted market prices for the same or similar issues.

7. RETIREMENT BENEFITS

The Company has noncontributory retirement annuity plans which cover substantially all employees. Benefits are based principally on the employee's length of service and compensation for the five highest paid years out of the last 10 years of service. It is the Company's policy to fund pension costs accrued each year to the extent deductible for federal income tax purposes. The net pension benefit for 1992, 1991, and 1990 totaled $1.5 million, $2.9 million, and $4.9 million, respectively.

Effective January 1, 1993, the retirement benefit plans for hourly and salaried employees were combined into one plan. Combining the two plans will not affect benefit levels.

Net pension benefit for 1992, 1991, and 1990 included the following components:

	1992	1991	1990
		(Thousands)	
Service cost: Benefits earned during the year	$15,387	$13,252	$11,968
Interest cost on projected benefit obligation	35,253	32,096	28,636
Actual return on plan assets	(60,020)	(111,749)	(6,499)
Net amortization and deferral	7,844	63,487	(39,017)
Net pension benefit	$(1,536)	$(2,914)	$(4,912)

The funded status of the plans at December 31, 1992 and 1991 were:	1992	1991
	(Thousands)	
Actuarial present value of accumulated benefit obligation:		
Vested	$287,504	$270,052
Nonvested	42,286	34,067
Total	$329,790	$304,119
Fair value of plan assets	$701,893	$659,993
Actuarial present value of projected benefit obligation	(480,429)	(440,519)
Plan assets in excess of projected benefit obligation	221,464	219,474
Unrecognized net transition asset	(80,850)	(88,103)
Unrecognized net (gain) loss	(139,729)	(132,642)
Unrecognized prior service cost	5,209	5,578
Net pension asset	$6,094	$4,307

Plan assets primarily consist of equity securities, corporate, U.S. agency, and Treasury bonds, and cash equivalents.

For 1992, 1991, and 1990, the projected benefit obligation was measured using an assumed discount rate of 7.75%, 7.75%, and 8%, respectively, and a long-term rate of increase in future compensation levels of 6%, while the net pension benefit was measured using an expected long-term rate of return on plan assets of 7.5%.

In addition to providing pension benefits, the Company provides certain postretirement benefits for retired employees and their dependents. Substantially all of the Company's employees who retire under a Company pension plan may become eligible for those benefits at retirement. At December 31, 1992, 1991, and 1990, 1,905, 1,866, and 1,785 retirees and their dependents, respectively, were covered under the Company's comprehensive health insurance plan and prescription drug plan, which the Company self-insures. The cost of providing those benefits to retirees was approximately $5 million, $4.4 million, and $4.1 million in 1992, 1991, and 1990, respectively.

The Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106) in December 1990. SFAS 106 requires that the Company accrue a liability for estimated future postretirement benefits during an employee's working career rather than recognize an expense when benefits are paid. SFAS 106 is effective for fiscal years beginning after December 15, 1992.

The Company adopted SFAS 106 in January 1993. At the time of adoption, the actuarially determined accumulated postretirement benefit obligation attributable to eligible plan participants and eligible dependents was $225 million. The Company plans to recognize the accumulated benefit obligation over 20 years in accordance with SFAS 106. Adoption of the new standard is expected to increase annual expenses, before deferral for ratemaking purposes, by about $32 million, or 7 times the 1992 expense.

In March 1992, the PSC issued a draft Statement of Policy concerning the accounting and ratemaking treatment for postretirement benefit costs. This draft policy provides for, among other things, recovery in rates for deferred SFAS 106 costs. In addition, the draft policy proposes that deferred SFAS 106 costs will be recovered in rates within 10 years of the adoption of SFAS 106. The Statement of Policy is expected to be approved by the PSC during the spring of 1993. In addition, the July 1992 rate decision allows the Company's to recover a portion of SFAS 106 costs in revenues from its customers and to defer the remainder of these costs for recovery, in accordance with the draft Statement of Policy. The Company anticipates that future SFAS 106 costs will be recoverable through rates.

8. JOINTLY-OWNED GENERATING STATIONS

Nine Mile Point Unit 2

The Company has an undivided 18% interest in the output and costs of the Nine Mile Point nuclear generating unit No. 2 (NMP2) which is being operated by Niagara Mohawk Power Corporation (Niagara Mohawk). Ownership of NMP2 is shared with Niagara Mohawk 41%, Long Island Lighting Company 18%, Rochester Gas and Electric Corporation 14%, and Central Hudson Gas & Electric Corporation 9%. The Company's share of the rated capability is 188,000 kilowatts. The Company's net utility plant investment, excluding nuclear fuel, was approximately $660 million and $679 million, at December 31, 1992 and 1991, respectively. The accumulated provision for depreciation was approximately $90 million and $72 million, at December 31, 1992 and 1991, respectively. The Company's share of operating expenses is included in the Consolidated Statements of Income.

An interim operating agreement that provided for policy, budget, and management oversight functions of NMP2 by the four non-operating cotenants expired on December 31, 1992. Effective January 1, 1993, an operating agreement replaced the interim operating agreement, and its terms are substantially the same. The operating agreement, which expires December 31, 1994, provides for automatic extensions unless terminated by one or more of the cotenants after appropriate notice. The operating agreement is subject to PSC approval.

In August 1992, the Nuclear Regulatory Commission (NRC) issued a systematic assessment of licensee performance (SALP) review of the Nine Mile Point Station (includes both Nine Mile Point nuclear generating unit No. 1 and NMP2) for the period April 1991 through May 1992. The SALP report indicated that NMP2 operates safely and is a good overall performer. The ratings for plant operations, engineering/technical support, radiological controls, safety assessment/quality verification, and maintenance/surveillance remained at Category 2, representing good performance. Emergency preparedness and security safeguards remained at Category 1, representing superior performance.

A low level radioactive waste management and contingency plan has been developed for NMP2 and provides assurance that it is properly prepared to handle interim storage of low level radioactive waste until 1998.

Niagara Mohawk has contracted with the U.S. Department of Energy (DOE) for disposal of high level radioactive waste (spent fuel) from NMP2. The DOE announced in early 1990 that the schedule for start of operations of their high level radioactive waste repository had slipped from 2003 to no sooner than 2010. The Company has been advised by Niagara Mohawk that the NMP2 Spent Fuel Storage Pool has a capacity for spent fuel that is adequate until 2014. If further DOE schedule slippage should occur, the recent development of pre-licensed dry storage facilities for use at any nuclear power plant extends the on-site storage capability for spent fuel at NMP2 beyond 2014.

NMP2's next refueling outage is anticipated to begin in September 1993.

Nuclear Insurance

Niagara Mohawk maintains public liability and property insurance for NMP2. The Company reimburses Niagara Mohawk for its 18% share of those costs.

The Price-Anderson Amendments Act of 1988 increased the public liability limit for a nuclear incident to approximately $7.6 billion. Should losses stemming from a nuclear incident exceed the commercially available public liability insurance, each licensee of a nuclear facility would be liable for up to a maximum of $63 million per incident, payable at a rate not to exceed $10 million per year.

The Company's maximum liability for its 18% interest in NMP2 would be approximately $11 million per incident. The $63 million assessment is subject to periodic inflation indexing and a 5% surcharge should funds prove insufficient to pay claims associated with a nuclear incident. The Price-Anderson Act also requires indemnification for precautionary evacuations whether or not a nuclear incident actually occurs.

Niagara Mohawk maintains nuclear property insurance for NMP2. Niagara Mohawk has procured property insurance aggregating approximately $2.6 billion through the Nuclear Insurance Pools and the Nuclear Electric Insurance Limited (NEIL). In addition, the Company has purchased NEIL insurance coverage for the extra expense incurred in purchasing replacement power during prolonged accidental outages. Under NEIL programs, should losses resulting from an incident at a member facility exceed the accumulated reserves of NEIL, each member, including the Company, would be liable for its share of the deficiency. The Company's maximum liability under the property damage and replacement power coverages is approximately $2.3 million.

Nuclear Fuel Disposal and Nuclear Plant Decommissioning Costs

Niagara Mohawk has contracted with the DOE for the disposal of nuclear fuel. The Company is reimbursing Niagara Mohawk for its 18% share of the cost under the contract (currently approximately $1 per megawatt hour of net generation).

The Company has been informed by Niagara Mohawk that its 18% share of the cost to decommission NMP2 is currently estimated to be $235 million in 2027, when decommissioning is expected to commence. Included in the Company's current electric rates is an annualized allowance of approximately $1.6 million, based on Niagara Mohawk's estimate, which the Company expects will provide for its 18% share of decommissioning NMP2 in 2027.

In March 1990, the Company established a Qualified Fund under applicable provisions of the federal tax law. The fund also complies with NRC regulations which require the use of an external trust fund to provide funds to decommission the contaminated portion of NMP2. The balance in this fund was approximately $3.9 million and $2.4 million at December 31, 1992 and 1991, respectively, and is included in other property and investments on the Consolidated Balance Sheets. Niagara Mohawk filed a decommissioning report for NMP2 with the NRC. The report outlined the proposed plans, which included the Company's funding plan, to provide financial assurance to fund costs to decommission NMP2 when its license expires.

Homer City

The Company has an undivided 50% interest in the output and costs of the Homer City Generating Station, which is comprised of three generating units. The station is owned with Pennsylvania Electric Company which operates the facility. The Company's share of the rated capability is 952,000 kilowatts and its net utility plant investment was approximately $251 million and $257 million at December 31, 1992 and 1991, respectively. The accumulated provision for depreciation was approximately $148 million and $144 million, at December 31, 1992, and 1991, respectively. The Company's share of operating expense is included in the Consolidated Statements of Income.

9. COMMITMENTS AND CONTINGENCIES

Construction Program

The Company has made substantial commitments in connection with its construction program and estimates that 1993 costs will approximate $271 million. The program is subject to periodic review and revision, and actual construction costs may vary because of revised load estimates, imposition of additional regulatory requirements, and the availability and cost of capital.

Environmental Matters

The Company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Compliance programs will very likely increase the cost of electric and natural gas service by requiring changes to its operations and facilities. Historically, rate recovery has been authorized for the cost incurred for compliance with environmental laws and regulations.

Due to existing and proposed legislation and regulations, and legal proceedings commenced by governmental bodies and others, the Company may also incur costs from the disposal of hazardous substances produced during the Company's operations or those of its predecessors. The Company has been notified by the U.S. Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation that the Company is among the potentially responsible parties who may be liable to pay for costs incurred to remediate certain hazardous substances at 9 waste sites, not including the Company's inactive gas manufacturing sites which are discussed below. With respect to the 9 sites, 1 site is included on the Federal National Priorities List, 1 site is unlisted but is the subject of an EPA administrative order, and 7 sites are included in the New York State Registry of Inactive Hazardous Waste Sites (New York State Registry). Any liability may be joint and several for certain of these sites. The ultimate cost to remediate these sites will be dependent on such factors as the remedial action plan selected, the extent of site contamination, and the portion attributed, if any, to the Company. As a result, the Company is unable to estimate the extent of possible remediation costs. There is no clear precedent with the PSC for rate recovery of these types of remediation costs. However, since the PSC has previously allowed the Company to recover similar costs in rates (e.g., investigation and clean-up costs relating to coal tar sites), the Company expects to recover any remediation costs that it may incur.

A number of the Company's inactive gas manufacturing sites have been listed in the New York State Registry. The Company has filed petitions to delist the majority of the sites. The Company's program to investigate and initiate remediation at its 38 known inactive gas manufacturing sites has been extended through 2000. Estimated expenditures over this time period are $25 million, which are reflected in the Company's Consolidated Balance Sheets at December 31, 1992, to investigate and initiate remediation, as necessary, at the known gas manufacturing sites. The Company expects to recover such expenditures in rates, as the Company has previously been allowed by the PSC to recover such costs in rates.

The Clean Air Act Amendments of 1990 (1990 Amendments) will result in significant future expenditures for the reduction of sulfur dioxide, nitrogen oxides, and possibly toxic emissions at several of the Company's coal-fired generating stations. Under the 1990 Amendments, the Company must reduce its annual sulfur dioxide emissions by 49% from approximately 138,000 tons in 1989 to 71,000 tons by 2000. The Company estimates that over a 25-year period the cost to comply with the sulfur dioxide and nitrogen oxide limitations specified in the 1990 Amendments is approximately $252 million (on a present value basis) for all capital and operating and maintenance expenses, of which $17.3 million has been incurred to date. This cost includes $159 million for an innovative flue gas desulfurization (FGD) system and a nitrogen oxide reduction system expected to be completed in 1995 at the Company's Milliken Generating Station (Milliken).

In September 1991, the Company was selected by the DOE to receive federal funds for these systems. In October 1992, the DOE approved $45 million for these systems. In addition, the Company expects to receive funding totaling up to $17 million from other sources. The Company estimates that a 2% electric rate increase will be required for the cost of reducing sulfur dioxide and nitrogen oxides emissions for both Phase I (begins January 1, 1995) and Phase II (begins January 1, 2000).

The cost of controlling toxic emissions, if required, cannot be estimated at this time. Regulations may be adopted at the state level which would limit emissions even further, at an additional cost to the Company. The Company anticipates that the costs incurred to comply with the 1990 Amendments will be recoverable through rates based on previous rate recovery of required environmental costs.

The 1990 Amendments require the EPA to allocate annual emissions allowances to each of the Company's coal-fired generating stations based on statutory emissions limits. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. During Phase I, the Company estimates that it will have allowances in excess of the affected coal-fired generating stations' actual emissions. The Company is considering various methods of using, banking, or selling these excess emissions allowances. During Phase II, the Company estimates that the annual tons emitted by its coal-fired generating stations will equal its annual emissions allowances.

In addition to the annual emissions allowances allocated to the Company by the EPA, the Company may obtain extension

9. COMMITMENTS AND CONTINGENCIES (Continued)

rve allowances that the EPA will issue to companies electing to build scrubbers in Phase I such as the FGD system at Milliken. Due to the uncertainty of how many extension reserve allowances will be demanded, the extent to which the demand may exceed the supply, and the method of allocating extension reserve allowances, the Company entered into a pooling agreement with other utilities which are eligible to receive some of the extension reserve allowances. This agreement provides assurance that the Company will receive some of the extension reserve allowances in the event that demand exceeds supply.

Long-Term Power Purchase Contracts

The Company has on line and under contract 347 megawatts (mw) of NUG power. In addition, another 257 mw of NUG power is under construction. The Company is required to make payments under these contracts only for the power it receives. During 1992, 1991, and 1990 the Company purchased approximately $71 million, $30 million, and [illegible] million, respectively, of NUG power. The Company estimates that it will purchase approximately $151 million, $251 million, and $287 million of NUG power for the years 1993, 1994, and 1995, respectively. The requirement to purchase NUG power is expected to be a major contributor to rate increases over the next 3 years, and is expected to increase rates by approximately 8% during this time period.

In June 1992, the Company entered into an agreement with Indeck Energy Services of Kirkwood, Inc., Indeck Energy Services, Inc., and Indeck Kirkwood Limited Partnership to terminate the power purchase agreement for the 55 mw Indeck-Kirkwood project. The termination agreement will save ratepayers an estimated $350 million over 20 years. In January 1993, the PSC approved full recovery of the $11.5 million in termination costs in rates.

In December 1992, the Company entered into an agreement with Kamine/Besicorp Corning L.P., Kamine South Corning Cogen Co., Inc., and Beta South Corning, Inc. to terminate the power purchase agreement for the 79 mw South Corning cogeneration project. The termination agreement will save customers an estimated $300 million over 25 years. The Company plans to petition the PSC in early 1993 to recover $34 million in termination costs in rates. Terminating these agreements is part of a continuing effort by the Company to minimize future rate increases associated with uneconomical power purchases from NUGs.

As a result of the PSC's competitive bidding program, the Company is contracting for 25 mw in conservation projects to be available by November 1994. In accordance with a PSC ruling issued in October 1992, the Company will conduct an auction for an additional 10 mw of conservation projects. The timing of the auction has not yet been determined, but the Company does not expect that those conservation projects will be available before 1995. The Company expects to recover the costs associated with these contracts from its customers. The Company will utilize various methods, including competitive bidding, to minimize the economic impacts on customers of adding new resources to its system, while maintaining the Company's current level of system reliability.

Coal Purchasing Contracts

The Company has long-term contracts with nonaffiliated mining companies for the purchase of coal for the jointly-owned Homer City Generating Station. The contracts, which expire between 1995 and the end of the expected service life of the generating station, require the purchase of either fixed or minimum amounts of the station's coal requirements. The price of the coal under one of these contracts is based on recovery of production costs plus incentives. The remaining contracts are based on fixed price plus escalation provisions. The Company's share of the cost of coal purchased under these agreements is expected to aggregate $55 million for 1993.

In addition, the Company has a long-term contract for the purchase of coal for the Kintigh Generating Station. The contract, which expires in 1997, supplies the annual coal requirements of the station. One-third of the tonnage price is renegotiated annually to reflect market conditions. The delivered cost of coal purchased under this agreement is expected to be $56 million for 1993.

Federal Energy Regulatory Commission (FERC) Proceeding

In August 1991 and October 1992, the FERC issued orders which revised its generic policy related to filing requirements for contracts determined to be subject to its jurisdiction under the Federal Power Act. Under the revised policy, FERC may require a utility to refund certain revenues collected under late-filed contracts.

In December 1992, FERC issued a notice requesting comments from interested parties relating to its filing requirements for contracts. The notice solicited comments on whether the obligation to file jurisdictional agreements should extend to certain terminated agreements as well as existing agreements. The Company and many other utilities filed comments in January 1993 challenging the filing requirements and the appropriateness of the refund obligations.

The Company continues to review its compliance with FERC contract filing requirements. In October 1992, the Company determined that it may be required to file at least four additional contracts with FERC. The Company is unable to predict what actions FERC may take as a result of its notice and is unable to estimate the amount and timing of refunds, if any, that may be required. Therefore, the Company cannot predict the ultimate disposition of this matter, but believes that it will not have a material adverse effect on its financial position.

10. INDUSTRY SEGMENT INFORMATION

Certain information pertaining to the electric and natural gas operations of the Company is:

	1992		1991		1990	
	Electric	Natural Gas	Electric	Natural Gas	Electric	Natural Gas
			(Thousands)			
Operating						
Revenues	$1,451,525	$240,164	$1,367,936	$187,879	$1,334,509	$162,271
Expenses	$1,146,619	$221,307	$1,056,969	$177,751	$1,021,669	$147,278
Income	$304,906	$18,857	$310,967	$10,128	$312,840	$14,993
Depreciation and amortization*	$150,549	$8,428	$145,700	$6,680	$142,286	$5,373
Construction expenditures	$210,185	$35,433	$210,127	$35,756	$187,660	$23,065
Identifiable assets**	$4,490,436	$373,269	$4,420,166	$330,754	$4,355,218	$236,328

**Included in operating expenses.*

***Assets used in both electric and natural gas operations not included above were $312,723, $173,916, and $145,885 at December 31, 1992, 1991, and 1990, respectively. They consist primarily of cash and cash equivalents, special deposits, prepayments, and unamortized debt expense.*

11. SUPPLEMENTARY INCOME STATEMENT INFORMATION

Charges for maintenance, repairs, and depreciation and amortization, other than those set forth in the Consolidated Statements of Income, were not significant in amount. Taxes, other than federal income taxes, are:

	1992	1991	1990
		(Thousands)	
Property	$81,640	$76,589	$73,495
Franchise and gross receipts	92,153	76,721	62,849
Payroll	17,096	15,467	14,179
Miscellaneous	10,052	9,408	8,247
Total Other Taxes	$200,941	$178,185	$158,770

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarter ended	March 31	June 30	Sept. 30	Dec. 31
	(Thousands, Except Per Share Amounts)			
1992				
Operating revenues	$489,847	$401,934	$367,833	$432,075
Operating income	$111,373	$82,755	$60,109	$69,526
Net income	$76,416	$46,772	$26,581	$34,199
Earnings for common stock	$71,167	$41,488	$21,320	$28,998
Earnings per share	$1.10	$.60	$.31	$.42
Dividends per share	$.53	$.53	$.54	$.54
Average shares outstanding	64,682	68,800	69,063	69,318
Common stock price*				
High	$29.63	$29.38	$32	$32.75
Low	$26.13	$26.75	$29.25	$30.38
1991				
Operating revenues	$443,581	$373,362	$349,626	$389,246
Operating income	$105,695	$81,992	$66,008	$67,400
Net income	$73,208(1)	$43,087	$29,374	$22,974(2)
Earnings for common stock	$68,909	$37,722	$23,997	$17,685
Earnings per share	$1.10	$.60	$.38	$.28
Dividends per share	$.52	$.52	$.53	$.53
Average shares outstanding	62,542	62,775	63,024	63,273
Common stock price*				
High	$26.75	$27	$27.63	$29.63
Low	$24.38	$24	$24.63	$26.63

(1) First quarter 1991 results reflect the stockholders' share of proceeds from the settlement of lawsuits relating to the design and construction of NMP2 which increased net income and earnings for common stock by $3.9 million, and increased earnings per share by 6.2 cents.

(2) Fourth quarter 1991 results reflect an adjustment to the Homer City Coal Cleaning Plant, which decreased net income and earnings for common stock by $3.5 million, and decreased earnings per share by 5.6 cents, and the stockholders' share of a settlement of an antitrust lawsuit which decreased net income and earnings for common stock by $1.9 million, and decreased earnings per share by 3 cents.

*The Company's common stock is listed on the New York Stock Exchange. The number of stockholders of record at December 31, 1992 was 61,183.

Dividend Limitations: After dividends on all outstanding preferred stock have been paid, or declared, and funds set apart for their payment, the common stock is entitled to cash dividends as may be declared by the Board of Directors out of retained earnings accumulated since December 31, 1946. Common Stock dividends are limited if Common Stock Equity (43.7% at December 31, 1992) falls below 25% of total capitalization, as defined in the Company's Certificate of Incorporation. Dividends on common stock cannot be paid unless sinking fund requirements of the preferred stock are met. The Company has not been restricted in the payment of dividends on common stock by these provisions. The retained earnings balances of $327,040 and $308,688 million as of December 31, 1992 and 1991, respectively, have been accumulated since December 31, 1946.

REPORT OF MANAGEMENT

The Company's management is responsible for the preparation, integrity, and objectivity of the consolidated financial statements, notes, and other information in this Annual Report. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles and include estimates which are based upon management's judgment and the best available information. Other financial information contained in this report was prepared on a basis consistent with that of the consolidated financial statements.

In recognition of its responsibility for the consolidated financial statements, management maintains a system of internal accounting controls which is designed to provide reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition, and the prevention and detection of fraudulent financial reporting. Management continually monitors its system of internal controls for compliance. The Company maintains an internal audit department which independently assesses the effectiveness of the internal controls. In addition, the Company's independent accountants, Coopers & Lybrand, have considered the Company's internal control structure to the extent they considered necessary in expressing an opinion on the consolidated financial statements. Management is responsive to the recommendations of its internal audit department and Coopers & Lybrand concerning internal controls and corrective measures are taken when considered appropriate. Management believes that as of December 31, 1992, the Company's system of internal controls provides reasonable assurance as to the integrity and reliability of the consolidated financial statements.

The Board of Directors oversees the Company's financial reporting through its Audit Committee. This Committee, which is comprised entirely of outside directors, meets regularly with management, the internal auditor, and Coopers & Lybrand to discuss auditing, internal control, and financial reporting matters. To ensure their independence both the internal auditor and independent accountants have free access to the Audit Committee, without management's presence.

James A. Carrigg

James A. Carrigg
Chairman, President and Chief Executive Officer

Sherwood J. Rafferty

Sherwood J. Rafferty
Vice President and Treasurer
(Chief Financial Officer)

Everett A. Robinson

Everett A. Robinson
Vice President and Controller
(Chief Accounting Officer)

REPORT OF INDEPENDENT ACCOUNTANTS

Coopers
& Lybrand

To the Stockholders and Board of Directors,
New York State Electric & Gas Corporation
and Subsidiary
Ithaca, New York

We have audited the accompanying consolidated balance sheets of New York State Electric & Gas Corporation and Subsidiary as of December 31, 1992 and 1991, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 1992. 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 consolidated financial position of New York State Electric & Gas Corporation and Subsidiary at December 31, 1992 and 1991, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles.

Coopers & Lybrand

New York, New York
January 29, 1993

SELECTED FINANCIAL DATA

(In Thousands - Except Per Share Amounts)	1992	1991	1990	1989	1988
Operating revenues	**$1,691,689**	$1,555,815	$1,496,780	$1,427,745	$1,340,169
Net income	**$183,968**	$168,643	$158,013	$157,779*	$171,467*
Earnings per share	**$2.40**	$2.36	$2.48	$2.53*	$2.81*.
Dividends declared and paid per share	**$2.14**	$2.10	$2.06	$2.02	$2.00
Average shares outstanding	**67,972**	62,906	58,678	57,138	56,239
Book value per share of common stock (year end)	**$22.85**	$22.16	$21.85	$21.29	$20.71
Interest charges	**$155,388**	$163,526	$173,390	$180,068	$199,730
AFDC and non-cash return	**$6,482**	$7,541	$5,776	$6,387	$28,788
Depreciation and amortization	**$158,977**	$152,380	$147,659	$148,375	$134,037
Other taxes	**$200,941**	$178,185	$158,770	$146,605	$136,706
Construction expenditures	**$245,618**	$245,883	$210,725	$192,022	$228,223
Total assets	**$5,176,428**	$4,924,836	$4,737,431	$4,670,283	$4,693,277
Long-term obligations, capital leases, and redeemable preferred stock	**$1,883,927**	$1,897,465	$1,766,457	$1,799,800	$1,837,648

**Net income and earnings per share for 1988 and 1989 include the effects of adjustments recorded in April 1988 and December 1989 to the 1987 Nine Mile Point nuclear generating unit No.2 write-off. Excluding those adjustments, net income and earnings per share for 1988 and 1989 were $165,377 and $2.70 and $151,998 and $2.43, respectively.*

GLOSSARY

Allowance for funds used during construction (AFDC): the cost of money used to finance a project which is added to construction costs and recovered over the life of the asset

Allowed return on common equity: the cost of common equity as determined by the PSC

Book value per share: common stock equity divided by the number of common shares outstanding for the period

Btu (British thermal unit): the quantity of heat required to raise the temperature of one pound of water by one degree fahrenheit at sea level

Common equity: the value of common stockholders' investment in a company along with retained earnings

Competitive bidding: a mandated process by which utilities must seek bids for additional generation or demand-side management projects

Dekatherm: a measure of heating value equal to one million Btu (1,000 cubic feet of natural gas (one mcf) equals approximately one dekatherm)

Demand-side management (DSM): the planning and implementation of programs designed to help residential, commercial, and industrial electric customers conserve energy

Earnings for common stock: earnings after all expenses are recognized and preferred dividends have been paid

Earnings per share: earnings for common stock for a given period divided by the average number of shares outstanding for the period

Embedded cost of long-term debt: the average interest rate on long-term debt outstanding at the end of the year

Heat rate: a measure of generating station efficiency often expressed as the number of Btu needed to generate one kilowatt-hour of electricity

Load factor: the average load of an electric or natural gas distribution system compared to its maximum load capability for a certain period of time, expressed as a percentage

Market-to-book ratio: an indication of the market's perception of a stock's value (a ratio of over 100 indicates that the market believes the stock is worth more than its book value)

Net income: earnings after all expenses are recognized, but before preferred dividends are paid

Non-utility generator (NUG): a non-traditional power generator that is also known as an independent power producer or energy service company

Peak load: the point of highest customer demand for electricity (the Company is a winter peaking utility; its record peak is 2,597 megawatts)

Price/earnings (P/E) ratio: a measurement of the market's perception of a company's growth potential (the higher the P/E ratio, the more potential the market believes there is for growth)

Retained earnings: the portion of earnings that is reinvested in the business and not paid out as dividends

Return on common equity: the rate of return earned on common equity calculated by dividing earnings for common stock by average common equity

Total shareholder return: the increase in the value of a shareholder's investment including dividends received and changes in the market price per common share

Transportation gas: natural gas purchased directly from a supplier by an end user and transported, for a fee, by a local distribution company such as the Company

Unbilled revenues: the estimated revenues attributable to energy which has been delivered to the Company's customers but for which the metered amount has not been billed to the customers

Watt: one ampere of electric current under one volt of pressure (one kilowatt is 1,000 watts; one kilowatt-hour is one kilowatt used for one hour, and one megawatt is 1,000 kilowatts or one million watts)

Yield: the return which dividends provide a shareholder calculated by dividing the current annualized dividend per share by the current market price per share

FINANCIAL AND OPERATING STATISTICS

	1992	1991	1990	1989	1988	1987	198
	(Thousands, except Per Share Amounts)						
OPERATING REVENUES							
Electric	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$1,191,806	$ 1,136,799	$768,717
Natural gas	240,164	187,879	162,271	161,077	148,363	152,839	184,997
TOTAL	1,691,689	1,555,815	1,496,780	1,427,745	1,340,169	1,289,638	953,714
OPERATING EXPENSES							
Fuel used in electric generation	262,531	274,877	274,245	279,075	253,326	249,520	200,895
Electricity purchased	95,026	45,808	34,613	26,019	19,432	29,638	68,781
Natural gas purchased	126,815	99,528	88,589	101,598	82,822	90,974	132,300
Other operating expenses	318,680	279,364	268,829	238,804	213,959	195,204	125,044
Maintenance	102,500	110,131	106,665	97,420	90,097	93,274	60,541
Depreciation and amortization	158,977	152,380	147,659	148,375	134,037	110,679	53,174
Federal income taxes	102,456	94,447	89,577	64,489	81,689	110,355	53,606
Other taxes	200,941	178,185	158,770	146,605	136,706	128,776	82,877
TOTAL	1,367,926	1,234,720	1,168,947	1,102,385	1,012,068	1,008,420	777,218
OPERATING INCOME	323,763	321,095	327,833	325,360	328,101	281,218	176,496
OTHER INCOME AND DEDUCTIONS	12,036	6,076	(1,508)	7,474	28,350	(73,876)	66,346
INCOME BEFORE INTEREST CHARGES	335,799	327,171	326,325	332,834	356,451	207,342	242,842
INTEREST CHARGES							
Interest on long-term debt	145,822	151,649	158,209	164,573	187,304	195,264	104,080
Other interest	9,566	11,877	15,181	15,495	12,426	7,057	5,186
Allowance for borrowed funds used during construction	(3,557)	(4,998)	(5,078)	(5,013)	(14,746)	(47,312)	(11,5
INTEREST CHARGES-NET	151,831	158,528	168,312	175,055	184,984	155,009	97,74
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	183,968	168,643	158,013	157,779	171,467	52,333	145,095
Cumulative effect for years prior to 1987 of accounting change for disallowed project costs (less applicable taxes of $95,434)	–	–	–	–	–	(210,914)	–
Cumulative effect for years prior to 1987 of accounting change for income taxes	–	–	–	–	–	(19,156)	–
NET INCOME (LOSS)	183,968	168,643	158,013	157,779	171,467	(177,737)	145,095
PREFERRED STOCK DIVIDENDS	20,995	20,330	12,662	12,975	13,492	13,662	22,610
EARNINGS (LOSS) AVAILABLE FOR COMMON STOCK	162,973	148,313	145,351	144,804	157,975	(191,399)	122,485
COMMON STOCK DIVIDENDS	144,621	131,875	121,302	115,224	112,252	145,794	75,484
RETAINED EARNINGS INCREASE (DECREASE)	$18,352	$16,438	$24,049	$29,580	$45,723	($337,193)	$47,001
Average number of shares of common stock outstanding	67,972	62,906	58,678	57,138	56,239	55,318	36,41
Earnings (Loss) per share	$2.40	$2.36	$2.48	$2.53	$2.81	($3.46)	$3.
Dividends paid per share	$2.14	$2.10	$2.06	$2.02	$2.00	$2.64	$2.1

FINANCIAL STATISTICS

	1992	1991	1990	1989	1988	1987	1982
FINANCIAL STATISTICS							
Return on average common stock equity-percent	10.6	10.7	11.4	11.5*	13.2*	12.2*	15.2
Percentage of AFDC and non-cash return to total earnings	4.0	5.1	4.0	4.6	15.5	50.3	44.5
Mortgage bond interest-times earned	3.1	3.0	2.9	2.9	2.6	1.6	2.7
Interest charges and preferred dividends-times earned	1.9	1.8	1.8	1.8	1.7	1.2	1.9
Book value per share of common stock (year end)	$22.85	$22.16	$21.85	$21.29	$20.71	$19.85	$22.39
Market value per share of common stock (year end)	$32.50	$29.00	$26.00	$28.88	$22.75	$20.88	$21.63
Dividend payout ratio (percent)	89.2	89.0	83.1	79.8	71.2	82.2**	62.5
Price earnings ratio (year end)	13.5	12.3	10.5	11.4	8.1	6.5**	6.4
PROPERTY, PLANT AND EQUIPMENT (INCLUDES CONSTRUCTION WORK IN PROGRESS)			(Thousands)				
Electric	$4,694,073	$4,537,356	$4,367,913	$4,217,920	$4,089,485	$3,885,989	$2,616,720
Natural gas	361,630	336,199	222,125	201,942	189,580	176,019	137,788
Common	205,345	189,135	175,703	155,340	129,860	100,252	50,432
TOTAL	$5,261,048	$5,062,690	$4,765,741	$4,575,202	$4,408,925	$4,162,260	$2,804,940
ACCUMULATED DEPRECIATION	$1,427,793	$1,309,829	$1,174,651	$1,063,630	$956,415	$855,198	$526,471
CAPITALIZATION (INCLUDES CURRENT MATURITIES)			(Thousands)				
Long-term debt	$1,891,036	$1,825,918	$1,815,686	$1,801,762	$1,985,276	$2,091,678	$1,123,789
Preferred stock	269,050	270,700	172,350	174,000	178,650	183,320	236,075
Common stock equity	1,586,474	1,405,147	1,364,344	1,225,184	1,174,028	1,106,518	888,594
TOTAL CAPITALIZATION	$3,746,560	$3,501,765	$3,352,380	$3,200,946	$3,337,954	$3,381,516	$2,248,458
CAPITALIZATION RATIOS (PERCENT)							
Long-term debt	50.5	52.2	54.2	56.3	59.5	61.9	50.0
Preferred stock	7.2	7.7	5.1	5.4	5.3	5.4	10.5
Common stock equity	42.3	40.1	40.7	38.3	35.2	32.7	39.5
NUMBER OF STOCKHOLDERS							
Common stock	61,183	59,593	60,585	62,552	66,689	70,441	76,073
Preferred stock	3,829	3,943	4,068	4,238	4,444	4,583	6,669
PAYROLL (INCLUDING PENSIONS, ETC.)			(Thousands)				
Charged to operations	$181,245	$163,421	$148,007	$140,415	$132,617	$134,484	$94,219
Charged to construction and other accounts	89,463	82,455	72,761	64,890	61,808	54,276	51,015
TOTAL	$270,708	$245,876	$220,768	$205,305	$194,425	$188,760	$145,234
Number of employees (year end)	4,888	4,842	4,599	4,558	4,494	4,498	4,426

*Return on average common stock equity for 1987 excludes the effects of the write-off of Nine Mile Point nuclear generating unit No.2 (NMP2) and Jamesport disallowed costs and the accounting change for income taxes.
The return on equity for 1988 and 1989 excludes the NMP2 write-off adjustments.
**Excludes the 1987 write-offs and accounting change.

ELECTRIC SALES STATISTICS

	1992	1991	1990	1989	1988	1987	198[illegible]
KILOWATT-HOUR (KWH) SALES (MILLIONS)							
Residential	5,472	5,297	5,319	5,233	5,148	4,905	4,412
Commercial	3,283	3,285	3,235	3,181	3,069	2,882	2,492
Industrial	3,082	3,068	3,175	3,210	3,159	3,018	2,621
Other	1,457	1,457	1,468	1,431	1,400	1,372	1,201
TOTAL RETAIL	13,294	13,107	13,197	13,055	12,776	12,177	10,726
Other electric utilities	6,003	5,066	4,750	4,461	3,896	4,295	1,827
TOTAL	19,297	18,173	17,947	17,516	16,672	16,472	12,553
OPERATING REVENUES (THOUSANDS)							
Residential	$601,042	$553,056	$521,688	$510,941	$507,428	$483,531	$325,124
Commercial	314,272	293,197	267,598	261,606	257,707	244,416	163,755
Industrial	225,832	207,933	196,016	196,701	198,344	190,806	128,633
Other	133,819	124,575	116,352	114,364	113,576	110,846	72,357
TOTAL RETAIL	1,274,965	1,178,761	1,101,654	1,083,612	1,077,055	1,029,599	689,869
Other electric utilities	143,414	131,412	145,104	134,108	89,784	109,453	64,780
Unbilled revenue recognition - net	(427)	35,333	42,995	–	–	–	–
Other operating revenues	33,573	22,430	44,756	48,948	24,967	(2,253)	14,068
TOTAL OPERATING REVENUES	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$1,191,806	$1,136,799	$768,717
OPERATING REVENUES PER KWH (CENTS)							
Residential	10.98	10.44	9.81	9.76	9.86	9.86	7.37
Commercial	9.57	8.93	8.27	8.22	8.40	8.48	6.[illegible]
Industrial	7.33	6.78	6.17	6.13	6.28	6.32	4.[illegible]
Other	9.18	8.55	7.93	7.99	8.11	8.08	6.02
Total Retail	9.59	8.99	8.35	8.30	8.43	8.46	6.43
Other electric utilities	2.39	2.59	3.05	3.01	2.30	2.55	3.55
NUMBER OF CUSTOMERS (YEAR END)							
Residential	699,387	692,922	685,898	676,590	665,296	653,398	604,936
Commercial	72,463	71,463	70,802	69,230	67,488	65,923	59,413
Industrial	1,508	1,506	1,498	1,465	1,437	1,411	1,338
Other	11,073	10,907	10,825	10,694	10,556	10,363	9,843
TOTAL	784,431	776,798	769,023	757,979	744,777	731,095	675,530
ANNUAL AVERAGE USE (KWH)*							
Residential	7,843	7,672	7,796	7,786	7,791	7,569	7,306
Commercial	45,258	45,864	45,826	46,095	45,600	43,787	41,895
Industrial (thousands)	2,047	2,047	2,142	2,200	2,226	2,134	1,956
ANNUAL AVERAGE BILL*							
Residential	$861	$801	$765	$760	$768	$746	$538
Commercial	4,333	4,093	3,791	3,791	3,829	3,713	2,753
Industrial	149,955	138,714	132,265	134,819	139,777	134,941	95,995

*Computed using the weighted average number of customers for the year.

ELECTRIC GENERATION STATISTICS

	1992	1991	1990	1989	1988	1987	1982
SYSTEM CAPABILITY (MEGAWATTS)							
Coal	2,415	2,412	2,414	2,414	2,405	2,386	1,731
Nuclear	188	196	194	193	194	–	–
Hydro	70	70	68	66	67	68	38
Internal Combustion	8	8	7	7	7	7	11
TOTAL GENERATING CAPABILITY	2,681	2,686	2,683	2,680	2,673	2,461	1,780
Purchased-Power Authority	489	488	487	487	510	509	768
-Other	347	110	53	9	–	–	350
Less: Firm Sales	(8)	–	–	(115)	(125)	–	–
TOTAL SYSTEM CAPABILITY	3,509	3,284	3,223	3,061	3,058	2,970	2,898
SYSTEM CAPABILITY (PERCENT)							
Coal	69	74	75	80	79	81	60
Nuclear	5	6	6	6	6	–	–
Hydro	2	2	2	2	2	2	1
TOTAL GENERATING CAPABILITY	76	82	83	88	87	83	61
Purchased-Power Authority	14	15	15	16	17	17	27
-Other	10	3	2	–	–	–	12
Less: Firm Sales	–	–	–	(4)	(4)	–	–
TOTAL SYSTEM CAPABILITY	100	100	100	100	100	100	100
PRODUCTION STATISTICS							
Annual load factor (percent)	74.6	68.9	69.4	64.7	63.5	65.5	65.1
Coal burned (thousands of net tons)	6,478	6,310	6,395	6,472	6,106	5,956	4,803
Coal heat value (Btu per lb.)	12,668	12,610	12,510	12,477	12,572	12,487	11,937
Btu per kwh generated (net)	9,902	9,898	9,936	9,931	9,881	9,897	10,670
KILOWATT-HOUR (KWH) PRODUCTION-NET (MILLIONS)							
Generated:							
Coal	16,709	16,157	16,211	16,345	15,589	15,025	10,748
Nuclear	922	1,180	743	773	639	60	–
Hydro	301	258	356	292	245	280	197
TOTAL GENERATED	17,932	17,595	17,310	17,410	16,473	15,365	10,945
Purchased-Power Authority	1,635	1,667	1,607	1,667	1,743	1,911	2,104
-Other	1,250	343	347	102	45	583	663
TOTAL	20,817	19,605	19,264	19,179	18,261	17,859	13,712
PRODUCTION EXPENSES (THOUSANDS)							
Generated	$375,209	$391,393	$391,977	$381,371	$351,963	$332,250	$248,278
Purchased-Power Authority	15,661	14,668	13,534	12,012	11,360	14,729	27,511
-NUG*	71,260	30,028	7,700	1,905	1,393	1,341	731
-Other	8,105	1,112	13,379	12,102	6,679	13,568	40,539
TOTAL	$470,235	$437,201	$426,590	$407,390	$371,395	$361,888	$317,059
COST PER KWH (MILLS)							
Generated	20.92	22.24	22.64	21.91	21.37	21.62	22.68
Purchased-Power Authority	9.58	8.80	8.42	7.21	6.52	7.71	13.08
-NUG*	56.56	63.48	62.10	56.03	55.72	55.88	52.21
-Other	21.39	21.67	30.41	40.47	26.61	18.84	52.99
Operating expense (excluding production)	12.15	11.34	11.70	10.57	9.62	9.79	8.39
TOTAL	34.74	33.64	33.84	31.81	29.96	30.05	31.51
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (THOUSANDS)							
Production	$470,235	$437,201	$426,590	$407,390	$371,395	$361,888	$317,059
Transmission	31,623	30,462	30,118	29,239	22,196	24,314	13,023
Distribution	64,428	62,763	58,876	54,420	49,737	55,673	36,495
Customer accounting	31,180	28,861	26,861	23,242	21,031	20,158	16,568
Customer service	31,390	24,345	27,625	23,426	20,527	12,047	4,457
Administrative and general	94,349	75,812	81,815	72,405	62,258	62,660	44,476
TOTAL	$723,205	$659,444	$651,885	$610,122	$547,144	$536,740	$432,078

*Non-utility generator

NATURAL GAS SALES STATISTICS

	1992	1991	1990	1989	1988	1987	19[illegible]
DEKATHERM (DTH) SALES (THOUSANDS)*							
Residential	24,913	18,115	14,809	15,331	14,818	13,897	15,688
Commercial	10,796	8,054	6,532	6,926	7,055	6,803	8,123
Industrial	1,689	1,788	2,023	2,167	3,121	3,038	9,804
Other	1,959	1,917	2,151	2,071	2,242	2,499	4,314
TOTAL RETAIL	39,357	29,874	25,515	26,495	27,236	26,237	37,929
Transportation of customer-owned natural gas	17,009	12,530	8,157	8,853	7,825	5,959	–
TOTAL	56,366	42,404	33,672	35,348	35,061	32,196	37,929
OPERATING REVENUES (THOUSANDS)*							
Residential	$152,325	$111,106	$94,531	$93,873	$83,115	$85,242	$83,167
Commercial	59,939	43,969	37,852	38,726	35,680	37,620	38,192
Industrial	8,092	8,640	10,267	10,437	12,821	13,909	43,383
Other	10,762	10,243	11,574	10,776	10,738	12,620	20,255
TOTAL RETAIL	231,118	173,958	154,224	153,812	142,354	149,391	184,997
Transportation of customer-owned natural gas	11,639	9,571	7,169	6,721	5,523	2,931	–
Unbilled revenue recognition - net	(3,626)	3,770	853	–	–	–	–
Other natural gas revenue	1,033	580	25	544	486	517	–
SUBTOTAL	9,046	13,921	8,047	7,265	6,009	3,448	–
TOTAL OPERATING REVENUES	$240,164	$187,879	$162,271	$161,077	$148,363	$152,839	$184,997
OPERATING REVENUES PER DTH							
Residential	$6.11	$6.13	$6.38	$6.12	$5.61	$6.13	$5.30
Commercial	5.55	5.46	5.79	5.59	5.06	5.53	4.70
Industrial	4.79	4.83	5.08	4.82	4.11	4.58	4.43
Other	5.49	5.34	5.38	5.20	4.79	5.05	[illegible]
Total Retail	5.87	5.82	6.04	5.83	5.24	5.71	[illegible]
Transportation	0.68	0.76	0.88	0.76	0.71	0.49	–
NUMBER OF CUSTOMERS (YEAR END)*							
Residential with house heating	182,795	178,625	117,429	114,497	111,543	108,515	103,033
Residential without house heating	13,181	12,906	8,360	8,079	8,340	8,220	9,057
Commercial with space heating	23,165	23,023	16,843	16,626	16,419	16,265	14,980
Commercial without space heating	2,282	2,241	1,548	1,476	1,444	1,408	1,383
Industrial	390	386	334	343	343	400	386
Transportation of customer-owned natural gas	389	342	277	228	214	149	–
Other	1,657	1,557	1,246	1,154	1,133	1,202	1,141
TOTAL	223,859	219,080	146,037	142,403	139,436	136,159	129,980
ANNUAL AVERAGE USE (DTH)**							
Residential	129	105	119	126	125	120	140
Commercial	428	345	358	386	398	387	514
Industrial	4,387	4,781	6,003	6,246	8,694	7,614	25,531
ANNUAL AVERAGE BILL**							
Residential	$786	$641	$763	$774	$703	$738	$742
Commercial	2,377	1,882	2,076	2,158	2,012	2,139	2,417
Industrial	21,018	23,102	30,466	30,079	35,713	34,860	112,977
COST OF NATURAL GAS PURCHASED							
Amount (thousands)	$126,815	$99,528	$88,589	$101,598	$82,822	$90,974	$132,300
Per dth	$3.22	$3.30	$3.64	$3.57	$3.02	$3.43	$3.49
NATURAL GAS OPERATION AND MAINTENANCE EXPENSES (THOUSANDS)							
Production	$126,984	$101,458	$88,901	$102,014	$83,155	$91,369	$132,[illegible]
Transmission and distribution	19,938	18,491	13,982	13,247	11,712	11,570	[illegible]
Customer accounting	9,233	8,046	5,765	4,990	4,516	4,656	3,9[illegible]
Customer service	8,152	6,533	5,942	3,972	3,352	2,374	1,141
Administrative and general	18,040	15,735	6,464	8,571	9,758	11,901	8,661
TOTAL	$182,347	$150,263	$121,054	$132,794	$112,493	$121,870	$155,483

*The increase in 1991 is primarily due to the acquisition of Columbia Gas of New York, Inc.
**Computed using the weighted average number of customers for the year.

INVESTOR INFORMATION

Binghamton Executive Offices
4500 Vestal Parkway East
P.O. Box 3607
Binghamton, NY 13902-3607
(607) 729-2551

Ithaca Executive Offices
Ithaca-Dryden Road
P.O. Box 3287
Ithaca, NY 14852-3287
(607) 347-4131

General Counsel
Huber Lawrence & Abell
605 Third Avenue
New York, NY 10158

Independent Accountants
Coopers & Lybrand
1301 Avenue of the Americas
New York, NY 10019

To present certificates for transfer write to:
Chemical Bank
Attention: Stock Transfer Administration
P.O. Box 24935
Church Street Station
New York, NY 10249

(Certified or registered mail is recommended.)

For stock transfer instructions, write to:
Chemical Bank
Attention: Legal Transfer
450 West 33rd Street
New York, NY 10001

Please contact NYSEG shareholder services with questions regarding:

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

We are available between 8 a.m. and 4:30 p.m. (Eastern Time) on regular business days at 1-800-225-5643. Or you may write to:
New York State Electric & Gas Corporation
Attention: Shareholder Services
P.O. Box 3200
Ithaca, NY 14852-3200

You may also obtain a free copy of Form 10-K, which is filed each year with the Securities and Exchange Commission, by contacting shareholder services at the telephone number or address above.

Securities Listed on the New York Stock Exchange

- Common Stock
- 3.75% Preferred Stock
- 8.80% Preferred Stock
- 8.48% Preferred Stock ($25 par value)
- Adjustable Rate Preferred Stock ($25 par value)
- 7 5/8% First Mortgage Bonds (Due 2001)
- 8 5/8% First Mortgage Bonds (Due 2007)

Trading Symbol
The trading symbol for our common stock which is listed on the New York Stock Exchange is NGE.

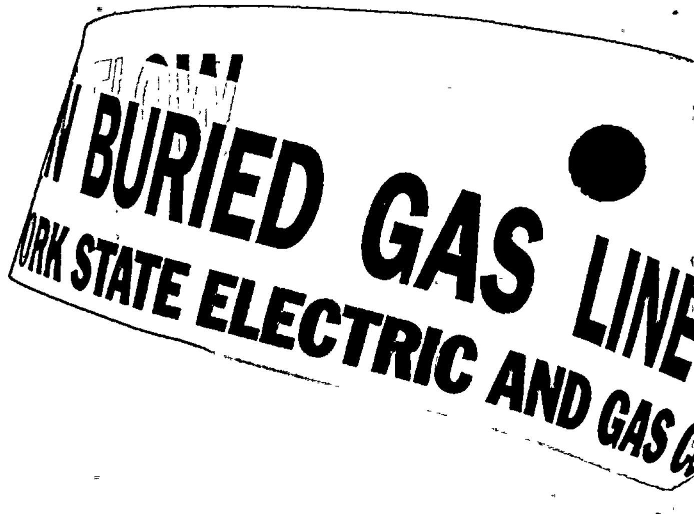
Annual Meeting
Friday, May 14, 1993 at 11 a.m.
Ithaca Executive Offices
Ithaca-Dryden Road
Dryden, NY

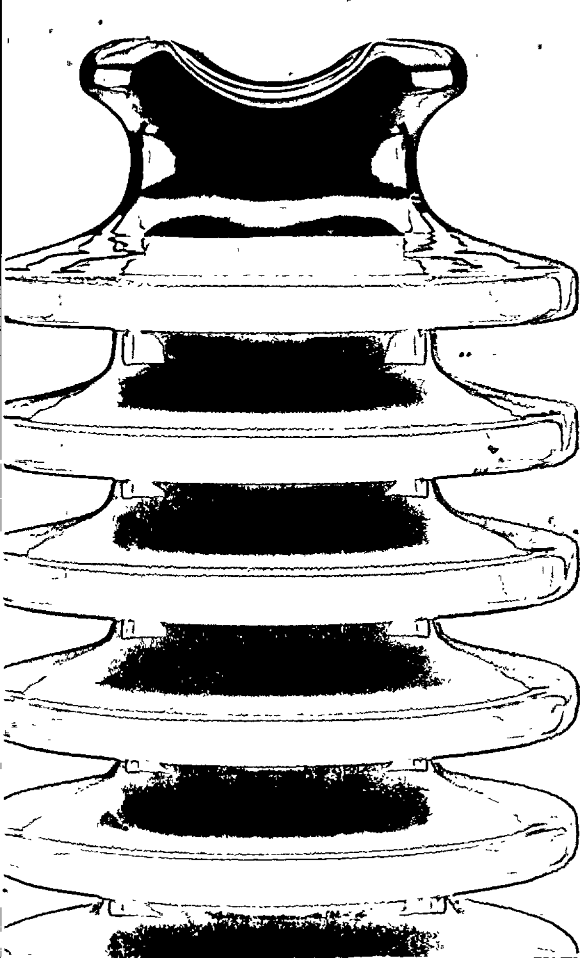
Formal notice of the meeting, a proxy statement and form of proxy will be mailed to stockholders in early April.

NYSEG

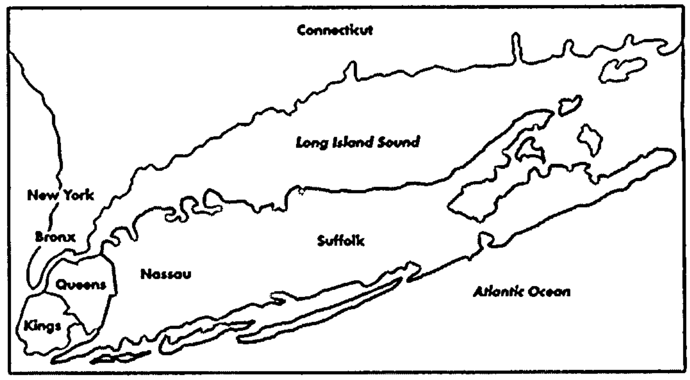
New York State Electric & Gas Corporation
Ithaca-Dryden Road
P.O. Box 3287
Ithaca, NY 14852-3287

BULK RATE
U
POSTA
New York State
Electric & Gas
Corporation






Meeting the challenge...



□ *Territory served by Long Island Lighting Company*

The Long Island Lighting Company's 6,500 employees provide electric and gas service to more than 1 million customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens County.

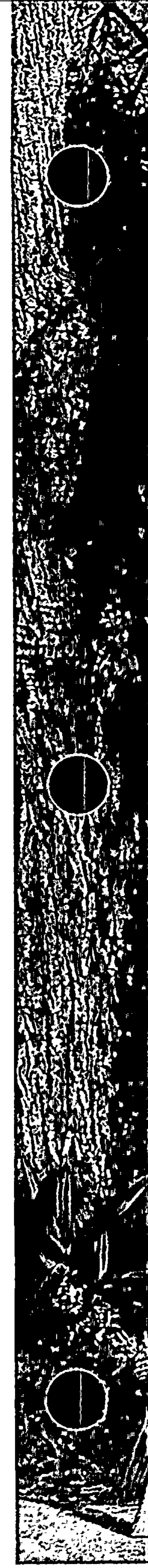
LILCO's service territory covers 1,230 square miles with a population of approximately 2.7 million people.

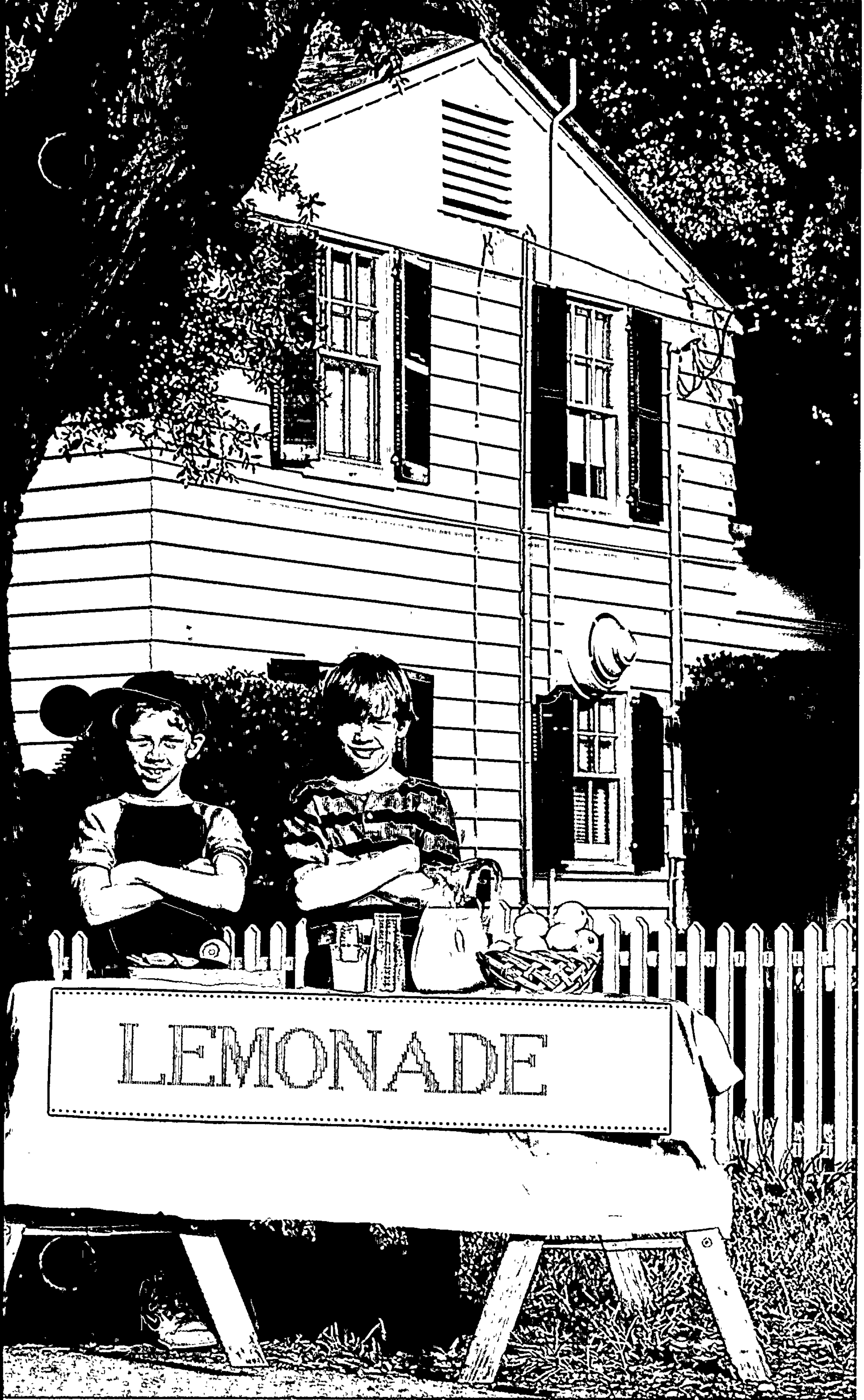
Meeting the challenge... **to serve.**

1992 Highlights

- Public Service Commission approved common stock dividend reinvestment plan
- First mortgage and general and refunding bonds upgraded one notch above investment grade
- Common stock trading at a 21-year high
- Common stock quarterly dividend increased to 43.5 cents

On the cover: Long Island's 1,180 miles of coastline offer some of the world's best recreation to swimmers, boaters and water sports enthusiasts.





LILCO's mission is to provide unparalleled service to our more than 1 million customers.

To Our Shareowners

In 1992, LILCO continued its trend of improving its financial performance. Earnings for the year were $238 million, or $2.14 per common share, with quarterly stock dividends increasing to 43.5 cents per share on October 1, 1992.

LILCO's improved financial position resulted in favorable actions by the rating agencies. In 1992, the Company's principal securities were upgraded for the third consecutive year, a show of confidence that allowed LILCO to refinance higher cost securities, saving the Company and our customers more than $17 million a year in interest expense.

In November, 1992, the Public Service Commission (PSC) approved a 4.1 percent increase in LILCO's electric rates, consistent with the 1989 Shoreham settlement. The Commission also approved a separate 7.1 percent increase in the Company's natural gas rates, that will allow us to expand natural gas service to more customers. Both increases became effective December 1, 1992.

Reshaping LILCO

For the past several years, LILCO has been examining its business to prepare the Company for success in the 1990s and beyond. A blueprint for the future was developed and, in 1992, LILCO moved forward with a three-year reorganization designed to position the Company to meet the challenges of the changing marketplace.

LILCO is committed to becoming a premier service organization, and has embarked on a gram to change its corporate culture. More than just moving boxes around on an organizational chart, we are seeking to fundamentally change the way we do business.

Business Units

The reorganization divides the Company's activities into three business units — Electric, Natural Gas and Energy Conservation — allowing each to concentrate on the energy service they are providing. In July, 1992, the Electric Business Unit was formed, with the Natural Gas and Conservation Units scheduled to be formed by the end of 1993.

Customer Service

In addition to dividing the Company into key competitive units, LILCO's reorganization incorporates two vital customer service elements. Later this year, we will be opening a "one-call center" in Melville, providing a single point of contact for customers conducting any type of business with LILCO. We will also be regionalizing the electric and gas businesses into four geographic locations to bring these services closer to the customer. Both steps are designed to improve LILCO's ability to respond to customer needs more efficiently and effectively.

Growing Long Island

In 1992, we not only developed a blueprint for LILCO's future, we helped map out Long Island's economic future. As the utility industry changes, so does the environment in which our Company does business. Decreases in defense spending and a nationwide recession have slowed local economic growth, but there are pockets of growth in Long Island's emerging technology industries. LILCO, along with Long Island's government and business communities, introduced an economic development campaign to help boost the region's economy.

In addition to targeting new and growing businesses, the campaign also promotes higher education and tourism on Long Island. These efforts have yielded significant results, with LILCO economic development specialists helping more than 175 businesses start up, expand or relocate to Long Island.

Meeting the Challenge

Facing both a changing industry and business environment, LILCO has worked throughout 1992 to position itself to meet the challenges of a more competitive marketplace. We seek a future in which LILCO becomes a model of service excellence and efficiency.

On behalf of LILCO's Board of Directors and Officers, I would like to thank you for your continued confidence in our leadership.

Sincerely,

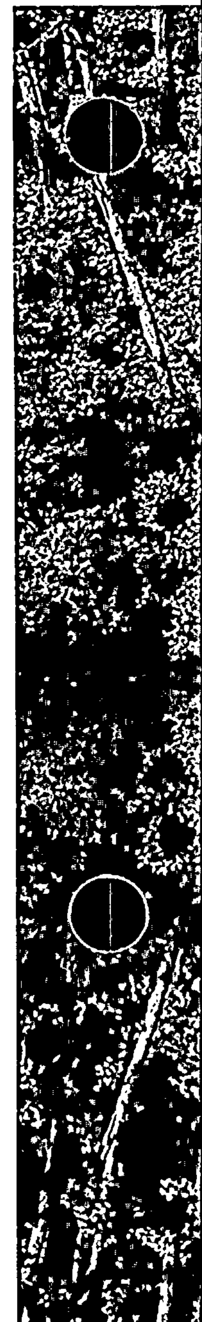
William J. Catacosinos
Chairman and Chief Executive Officer

To meet new challenges, utilities nationwide are altering the way they do business. Rapidly changing technology, more sophisticated customer demands, non-utility generating facilities, and increasing environmental regulations all point to a new era in the utility industry.

In 1992, the Long Island Lighting Company examined and discarded old utility paradigms and began to implement new strategies for success. While still in its infancy, the framework goes beyond simple changes in business practice to a new ideology for each and every employee — an understanding of LILCO's role in providing services to Long Island and

Meeting the challenge... to change.

the importance of each employee in the Company's success. In short, a blueprint for the future.



Meeting the Competition

The driving force behind changes at LILCO, and at utilities nationwide, is competition. Despite lingering public perception of the monopolistic power company, non-utility generation has grown tremendously in the last decade.

A recent industry study indicated that non-utility generators are currently contributing 43,114 megawatts of installed capacity to the U.S. electric supply, which represents eight percent of current U.S. electric capacity. In addition, non-utility generators have 65,690 megawatts in the pipeline — and the numbers are

Almost 50 percent of New York's nursery crops, such as shade trees, are produced on Long Island.

increasing each year. These new generating facilities are beginning to present some formidable competition. In 1992, 9.8 percent of the electricity delivered by LILCO was produced by non-utility generators.

LILCO's natural gas business is also functioning in an increasingly competitive market. With the northeast region the last national stronghold for home heating oil companies, natural gas' recent in-roads into this market have caused a multi-million dollar advertising campaign from a coalition of oil heat dealers.

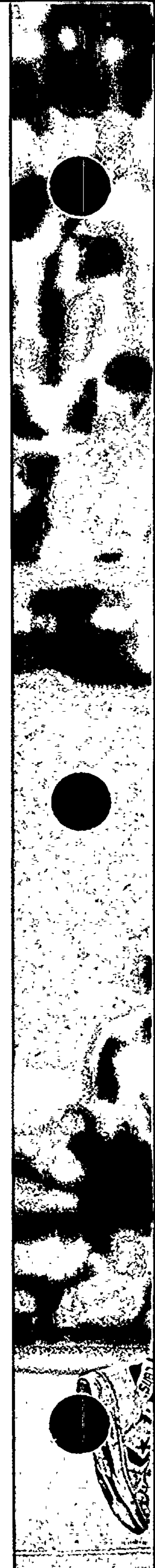
How then can traditional utilities survive? The answer lies in looking at ourselves in a non-traditional way — as a competitive business.

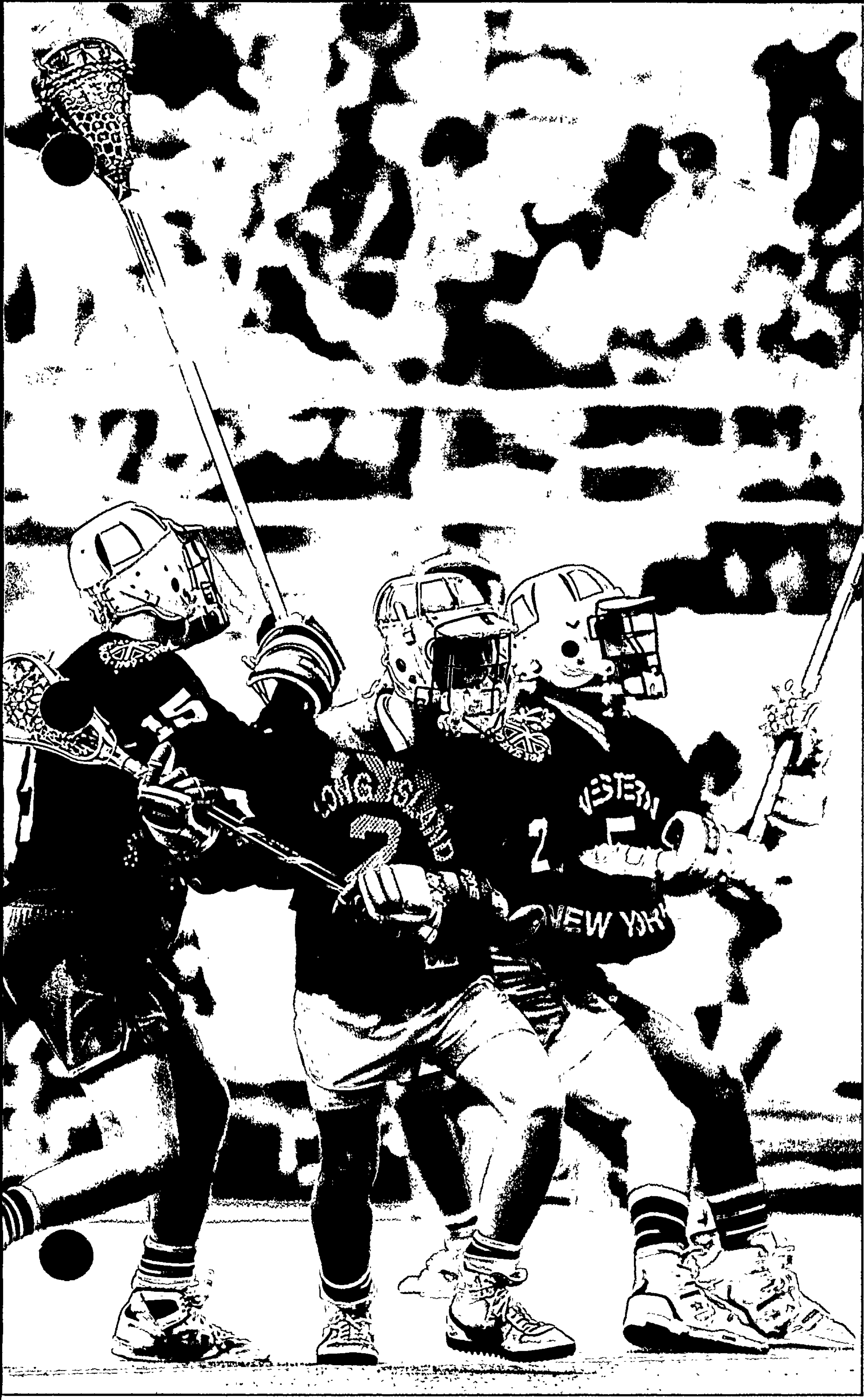
Meeting the challenge... to compete.

Through a reorganization into distinct business units — Electric, Natural Gas and Energy Conservation — LILCO has begun to restructure itself to meet the competitive challenge. More importantly, however, the Company is changing its attitudes and perceptions, recognizing that future success is dependent upon cost-conscious management and close attention to increasingly sophisticated customer demands.

Adapting and Evolving

Containing costs and providing unparalleled customer service are not mutually exclusive. In 1992, LILCO began to implement "cost-management" as opposed to simple cost-cutting. By taking an integrated approach to business planning, the Company is





Lacrosse is one of the many competitive sports that have a long history on Long Island.

eliminating costs that do not contribute to the value of services provided to our customers.

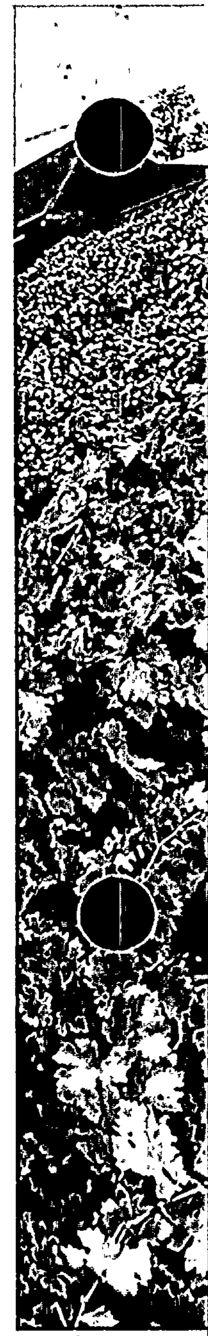
A key element of this new approach is integrated resource planning, which considers all available options to meet Long Island's long-term energy needs, including demand-side management, independent power producers and co-generation facilities, energy purchases from other utilities, and fuel substitution in our own plants. LILCO's plan combines these elements to provide cost-effective service in an environmentally acceptable manner.

Equally important in building the Company's competitive edge is an investment in our human

Meeting the challenge... **to adapt.**

resources. To enhance employee effectiveness, LILCO worked over the last year to bring each employee "on board" in terms of the Company's strategic plan.

Employees participated in empowerment workshops to prepare them to become part of the Company's future. Employee views were also sought on ways to improve service and increase productivity. With this change taking place in corporate culture, employees are adopting a service orientation that includes personal involvement and responsibility for achieving corporate objectives.



Looking Outside

While internal improvements were an important part of LILCO's growth in 1992, external forces

Long Island's agricultural heritage ranges from livestock and grain in colonial times to potatoes, sod and vineyards today.

played an equally vital role. The passage of the Clean Air Act Amendments and the National Energy Security Act have brought environmental concerns to the forefront of utility planning.

Air quality in particular was a key environmental concern in 1992, with motor vehicle emissions a primary focus of the new legislation. Since electricity and natural gas are currently the two leading alternative fuels for motor vehicles, LILCO is in a unique position to help Long Islanders respond to emissions concerns.

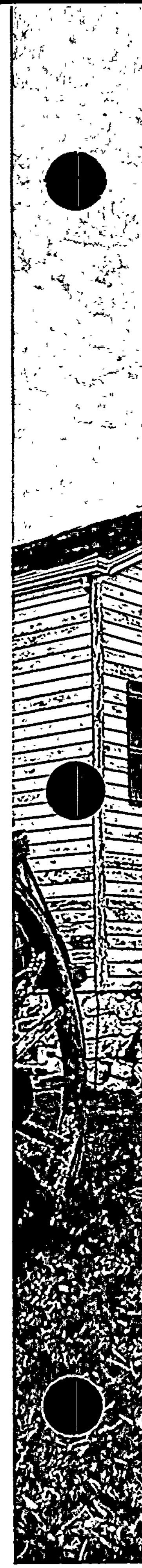
In 1992, LILCO was active in pursuing both alternative fuel options. With natural gas vehicles

Meeting the challenge...

to preserve.

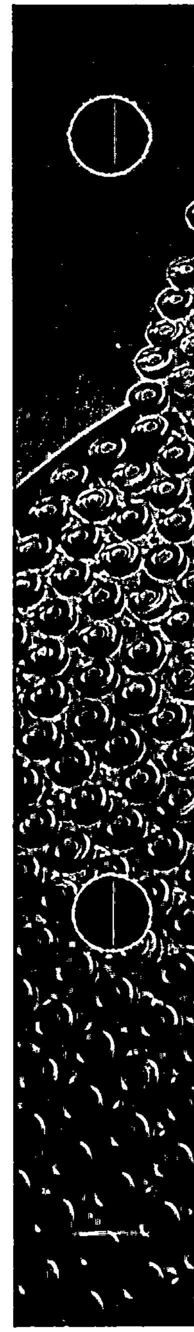
(NGVs) a more immediate clean air solution, the Company began adding NGVs to our own fleet, as well as providing information and assistance to other Long Island businesses. In December, 1992, we completed construction of the Island's first company-owned natural gas refueling station, commissioned by the Metropolitan Suburban Bus Authority.

LILCO is also supporting further developments in battery technology for electric vehicles, to make these zero-emission vehicles widely usable in the future. In October, 1992, we held a joint forum with representatives of major U.S. car manufacturers to discuss technology issues, production challenges, and local and national legislation.



Old Bethpage Village Restoration is a living museum of Long Island life in the 1800s.

LILCO's commitment to energy conservation expanded in 1992 as well, taking a more comprehensive approach to decreasing residential energy use through programs such as the New York State Energy-Star (NYSE-Star) program. As a NYSE-Star participant, LILCO provides incentives to residential developers who build homes that far exceed the state energy construction code.



Involvement and Innovation

In 1992, LILCO encouraged economic growth by spearheading an economic development campaign depicting Long Island's innovative business atmosphere,

Meeting the challenge... **to grow.**

excellent colleges and universities, and diverse cultural and tourism options. The Company's efforts were part of the New Long Island Partnership, a coalition of businesses and government agencies, working to attract, retain and expand businesses on the Island.

The effort has been successful. Since its inception, more than 70 companies have been involved with the economic development program, helping Long Island add or retain more than 7,000 jobs and $2 billion in annual sales.

Encouraging innovation is another method for generating economic growth. In the case of LILCO's Long Island Research and Development Initiative

More than 80 biotechnology companies comprise Long Island's newest, most rapidly growing industry.

there was an additional benefit — developing technologies that improve LILCO service.

In February, 1992, LILCO awarded more than $3.5 million in funding to Long Island institutions for 27 winning research and development projects, ranging from expert computer systems to gas leak detection devices to robotics. These projects, currently in various stages of development, represent approximately $5 million worth of work that will be performed locally.

Direction for the Future

Change, particularly change of ingrained beliefs and behaviors, takes time. The progress made in

Meeting the challenge... **to succeed.**

altering both LILCO's organization and culture will continue in 1993 and beyond. But the groundwork has been laid for forging a new, competitive business from the old utility model.

LILCO will remain focused on providing unparalleled service to all Long Islanders. In 1993, that will include the completion of our "one-call center," a single point of contact for all LILCO customer transactions.

And we will continue to seek innovation and improvement in technology and service as we grow and evolve to meet the challenge of the future.

Long Island offers a wealth of educational opportunities with 19 colleges and universities.

Overview

The year 1992 represents the fourth consecutive year of continued improvement in the Company's financial health.

The financial viability of the Company had been jeopardized in the past by the controversy concerning the Shoreham Nuclear Power Station (Shoreham) and the federal Racketeer Influenced and Corrupt Organizations Act (RICO Act) litigation. The 1989 Settlement between the Company and the State of New York (State) was designed to eliminate the controversy over Shoreham by providing for, among other matters, the transfer of Shoreham to an agency of the State and reciting the intention to return the Company to investment grade financial condition by providing rate increases in each year from 1989 through 1998. The Company's financial recovery began in 1989 following the 1989 Settlement and a class action settlement (Class Settlement) entered into between the Company and its ratepayers to resolve the RICO Act litigation.

The improvement in the Company's financial condition is evidenced, in part, by the elevation of the Company's First Mortgage Bonds and General and Refunding Bonds (G&R Bonds) to one notch above "minimum investment grade" and the elevation of the Company's unsecured debt and preferred stock to "minimum investment grade."

Other significant events in 1992 included:

- The transfer of ownership of Shoreham to an agency of the State on February 29, 1992.
- Approval, by the New York State Public Service Commission (PSC), of the second annual electric rate increase of 4.1% effective December 1, 1992, under the three-year electric rate plan approved in 1991.

  This three-year rate plan follows the receipt of electric rate increases in each of the years 1989 through 1991.
- The reinstatement of the Company's Automatic Dividend Reinvestment Plan beginning with the October 1, 1992 common stock dividend payment.
- An increase in the Company's common stock quarterly dividend from 42½ cents per quarter to 43½ cents per quarter.

  Earnings for common stock in 1992 were $2.14 per common share compared to $2.15 per common share in 1991. The 1992 results reflect a significant improvement in the Company's gas business earnings. The Company's electric business earnings were lower in 1992 as a result of the lower allowed rate of return which is prescribed by the PSC.
- The common stock traded on average at a twenty-one year high.
- The refinancing of a significant amount of the Company's securities as a result of very favorable long-term interest rates.

  The refinancing of approximately $1.5 billion of higher-cost securities which significantly lowered the Company's cost of debt and preferred stock. These 1992 refinancings will result in more than $17 million in annual cash savings through lower interest and preferred stock dividend expenses.

  Since the 1989 Settlement became effective, the Company's aggressive refinancing program has resulted in annual cash savings of approximately $70 million through lower interest and preferred stock dividend expenses.

  The elimination of all of the Company's outstanding bank debt of approximately $446 million.

  The conversion of $400 million of variable rate tax-exempt securities to a 30-year fixed annual rate of 7.15%.
- The issuance of $200 million of low-cost tax-exempt securities resulting in substantial savings for the Company's ratepayers since these securities carry significantly lower interest rates than taxable bonds.
- The addition of approximately 10,000 new gas space heating customers for the third consecutive year.
- An increase in gas rates of 7.1% effective December 1, 1992.

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).

Since 1989, the rating agencies have significantly upgraded their ratings on the Company's First Mortgage Bonds and G&R Bonds to one level above "minimum investment grade" and the Company's debentures and preferred stock to "minimum investment grade."

The chart below indicates the current ratings for each of the Company's principal securities and the minimum investment grade ratings used by each agency.

	Moody's	*S&P*	*Fitch*	*D&P*
First Mortgage Bonds	Baa2	BBB	BBB	BBB
G&R Bonds	Baa2	BBB	BBB	BBB
Debentures	Baa3	BBB−	BBB−	BBB−
Preferred Stock	baa3	BBB−	BBB−	BB+
Minimum Investment Grade	Baa3	BBB−	BBB−	BBB−

Rate Matters

Electric Pursuant to the 1989 Settlement, the Company received electric rate increases contemplated by the Rate Moderation Agreement (RMA), a constituent document of the 1989 Settlement discussed below, for each of the three rate years in the period ended November 30, 1991. In response to the Company's rate filing in December 1990, the PSC approved the Long Island Lighting Company Rate-making and Performance Plan (LRPP) in November 1991, which provides for annual electric rate increases of 4.15%, 4.1% and 4.0% effective December 1, 1991, 1992 and 1993, respectively. Effective December 1, 1992, the Company began receiving the second of the three annual electric rate increases provided for within the LRPP. The LRPP provides for an allowed return on common equity from electric operations of 11.6%.

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 reduces 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 over 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. The LRPP also contains a mechanism whereby earnings in excess of the allowed rate of return on common equity, excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners.

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 RMA provides for the full recovery of the FRA. The RMA, by its terms, specifies that the FRA is being 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 beginning 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. The RMC has provided the Company with a substantial amount of non-cash earnings since the 1989 Settlement became effective.

The RMA was designed to provide rate increases sufficient to recover the RMC within a ten-year period. The RMC balance has 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, has been deferred. The RMC balance will subsequently decrease and is expected to be fully amortized by November 30, 1999, as deferred revenue requirements are recovered.

The LRPP was designed to be consistent with the RMA's long-term goals including: (i) the recovery of the BFC; (ii) the recovery of the RMC in approximately ten years; (iii) the Company's return to investment grade financial condition and (iv) the Company's receipt of adequate and timely rate relief. Although the LRPP provides for slightly lower annual electric rate increases than originally anticipated in the 1989 Settlement, the Company believes that it will still fully recover the RMC within a ten-year period principally as a result of changes in the original assumptions. The revenues assumed by the LRPP are adequate to provide the Company with recovery of its revenue requirements under conventional ratemaking and recovery of the RMC balance over the remainder of the ten-year period. However, actual revenues may differ from those assumed for this period. The original assumptions underlying the RMA included projections of future revenues, operating expenses and required rates of return. Since then, the Company has experienced interest rates, operations and maintenance expenses, non-Shoreham property taxes and fuel expenses that are lower than those originally anticipated. As a result, amounts deferred in the RMC have been less than expected.

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

Gas In November 1992, the PSC approved a gas rate increase of 7.1%, or $35.7 million annually, effective December 1, 1992, with an allowed return on common equity from gas operations of 11.0%. In November 1991, the Company received a gas rate increase of 4.1% effective December 1, 1991.

On December 31, 1992, the Company filed an application with the PSC seeking gas rate relief for the three rate years beginning December 1, 1993. The Company has requested a gas rate increase of 6.7%, or $37.7 million in additional revenues to become effective for the first rate year under this filing. The Company's filing also includes a proposed methodology for determining rate increases, not to exceed approximately $30 million annually, for the subsequent second and third rate years. This filing reflects the Company's latest projections of capital expenditures, operations and maintenance expenses and the continued expansion of its gas business.

Results of Operations

Earnings Summary results of earnings for the years 1992, 1991 and 1990 were as follows:

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

	1992	1991	1990*
Net Income	$ 302	$ 306	$ 319
Earnings for Common Stock	$ 238	$ 239	$ 251
Earnings per Common Share	$ 2.14	$ 2.15	$ 2.26
Average Shares Outstanding	111.4	111.3	111.3
AFC & RMC Included in Net Income	$ 60	$ 183	$ 214
AFC & RMC – % of Net Income	20%	60%	67%

Excludes the effect of an accounting change for unbilled gas revenues.

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

The earnings in the electric business were lower in 1992 when compared to 1991. This lower level of earnings in the electric business was offset by the significant increase in the gas business earnings in 1992.

The increase in the gas business earnings was the result of higher revenues and continued cost containment programs. The higher gas revenues were due to the 1992 gas rate increase and the Company's aggressive gas expansion program, which has resulted in an increase in the number of gas space heating customers.

The electric business earnings for 1992 were lower as a result of the lower allowed rate of return of 11.6% in 1992 when compared to the allowed rate of return of 12.75% in 1991. The allowed rate of return is prescribed by the PSC.

Incentives earned for electric operations provided 6 cents per share in 1992 and 12 cents per share in 1991. In addition, for the rate year ended November 30, 1992, the Company earned $16.2 million, net of tax effects, in excess of its allowed rate of return on common equity which, in accordance with the LRPP, was shared equally between ratepayers and shareowners. These excess earnings were generated as a result of a reduction in operations and maintenance expenses and the effect of a decrease in capital expenditures included in rate base.

The decrease in earnings for common stock for 1991 of approximately $12 million, or 11 cents per share, compared with 1990, was primarily attributable to increases in non-fuel operations and maintenance expenses, operating taxes and interest expense, partially offset by higher electric revenues. 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.

Earnings for 1990 included 10 cents per common share attributable to a change in the Company's method of recognizing gas revenues. Effective January 1, 1990, the Company's revenues included estimated consumption of gas delivered to customers, but not yet billed at month end, resulting in the full accrual of all unbilled gas revenues. The cumulative effect of this accounting change increased 1990 earnings by nearly $12 million, net of tax effects. The Company did not earn in excess of its allowed rate of return for the rate year ended November 30, 1990.

Revenues Total revenues in 1992, including revenues from recovery of fuel costs, were $2.6 billion, which represents an increase of $74 million or 2.9% over 1991 revenues. Total revenues for the Company's electric and gas operations for the years 1992, 1991 and 1990 were as follows:

(In millions of dollars)

	1992	1991	1990
Electric	$ 2,195	$ 2,197	$ 2,096
Gas	427	351	361
Total Revenues	$ 2,622	$ 2,548	$ 2,457

Electric In 1992, electric revenues decreased $2 million when compared to 1991. Revenues in 1991 had increased $101 million or 4.8% over 1990. The changes in the level revenues when compared to the prior year resulted from following factors:

(In millions of dollars)

	'92/'91	'91/'90
Rate Increases	$ 85	$ 114
Sales Volumes	(74)	(7)
Fuel Cost Recoveries	(13)	(6)
Total	$ (2)	$ 101

Rate Increases The Company received electric rate increases of 4.1% effective December 1, 1992, and 4.15% effective December 1, 1991. These rate increases provided $85 million in additional revenues for 1992 when compared to 1991. A 5.0% rate increase effective December 1, 1990, provided $114 million in additional revenues for 1991 when compared to 1990.

Sales Volumes The decrease in revenue from sales volumes was primarily attributable to cooler weather experienced in the summer of 1992 when compared to the same period in 1991. The Company's current electric rate structure, discussed above under the heading "Rate Matters," provides for a revenue reconciliation mechanism which reduces the impact on earnings of experiencing electric sales that are above or below the levels reflected in rates. As a result of lower th adjudicated electric sales, the Company recorded non-c income which is included in "Other Regulatory Amortizatio of $78.5 million and $0.4 million in 1992 and 1991, respectively.

[illegible]att Hour Sales Summary of electric kilowatt hour (kWh) [illegible]for the years 1992, 1991 and 1990 were as follows:

	(In millions of kWh)		
	1992	*1991*	*1990*
Residential	6,788	7,023	7,022
Commercial/Industrial	8,652	8,791	8,832
System Sales	15,440	15,814	15,854
Power Pool Sales	227	598	532
Total Sales	15,667	16,412	16,386

The decrease in residential and commercial/industrial sales in 1992 was largely due to the cooler weather experienced during the summer months. Residential sales, which comprised 44% of system sales, were down by 3.3% when compared with 1991, while commercial/industrial sales, which accounted for 53% of system sales, declined by 1.7%. Power pool sales fluctuate with relative costs and power pool system availabilities.

The average number of electric customers served in 1992 and 1991 was approximately 1,009,000 and 1,005,000, respectively. The 4,000 customer increase in 1992 is similar to the increase experienced in 1991 when compared to 1990.

[illegible]nary of average use per customer for the years 1992, [illegible], and 1990 was as follows:

	(In kWh per customer)		
	1992	*1991*	*1990*
Residential	7,518	7,812	7,844
Commercial/Industrial	80,346	81,797	82,304
System	15,297	15,731	15,832

Fuel Cost Recoveries Total electric fuel cost recoveries for 1992 were down $13 million compared with 1991, primarily as a result of lower sales volumes, partially offset by an increase in the average cost of fuel. In 1991, fuel cost recoveries decreased by $6 million compared with 1990, principally due to a lower average cost of fuel.

Gas In 1992, gas revenues increased by $76 million, or 21.7%, when compared to 1991. Revenues in 1991 decreased by $10 million, or 2.8%, when compared to 1990. The changes in the level of revenues when compared to the prior year resulted from the following factors:

	(In thousands of dollars)	
	'92/'91	*'91/'90*
Rate Increases	$ 17	$ 2
Sales Volumes	50	(7)
[illegible]Cost Recoveries	9	(5)
[illegible]	$ 76	$ (10)

Rate Increases The Company received gas rate increases of 7.1% effective December 1, 1992, and 4.1% effective December 1, 1991. These rate increases provided $17 million in additional revenues in 1992 when compared to 1991. A gas increase of 1.3% in January 1990 provided $2 million in additional revenues for 1991 when compared to 1990.

Sales Volumes The increase in 1992 revenues due to sales volumes was primarily due to customer additions and conversions resulting from the Company's gas expansion program, aided by a colder heating season in 1992. The Company added approximately 10,000 new gas space heating customers to its system for the third consecutive year. Summary of gas decatherm (dth) sales for the years 1992, 1991 and 1990 were as follows:

	(In thousands of dth)		
	1992	*1991*	*1990*
Space Heating	48,751	41,323	41,081
Non-Space Heating	7,541	7,366	7,800
Total Firm	56,292	48,689	48,881
Interruptible	5,090	4,538	6,347
Total System	61,382	53,227	55,228

Summary of average use per customer for the years 1992, 1991 and 1990 was as follows:

	(In dth per customer)		
	1992	*1991*	*1990*
Space Heating	188	165	171
Non-Space Heating	42	40	41
Interruptible	9,568	9,614	15,480
System	140	123	129

Fuel Cost Recoveries Recoveries of fuel expenses in 1992 revenues increased by $9 million compared with 1991, primarily due to higher sales volumes. In 1991, fuel recovery revenues had decreased by $5 million, primarily due to lower sales volumes.

Fuel and Purchased Power Expenses for fuel and purchased power for electric operations and for gas delivered to customers decreased by $27 million in 1992 compared with 1991, and decreased by $18 million in 1991 compared with 1990. Summary of fuel and purchased power expenses for the years 1992, 1991, and 1990 were as follows:

	(In millions of dollars)		
	1992	*1991*	*1990*
Electric Fuel	$ 279	$ 381	$ 441
Purchased Power	281	213	170
Gas	182	175	176
Total	$ 742	$ 769	$ 787

The Company has substantially reduced its dependence on foreign oil for electric generation, substituting gas and purchased power whenever economical. Summary of electric fuel and purchased power mix for the years 1992, 1991 and 1990 were as follows:

(Percent of system energy requirements)	1992	1991	1990
Oil	37%	50%	56%
Gas	19	18	20
Purchased Power	38	25	20
Nuclear Fuel	6	7	4
Total	100%	100%	100%

Operations and Maintenance Expenses Total operations and maintenance expenses, excluding fuel and purchased power, for 1992, 1991 and 1990 were $498 million, $523 million and $476 million, respectively. The $25 million, or 4.8%, decrease in 1992 was primarily due to lower electric operations expenses which resulted from the Company's aggressive expense reduction and cost containment programs. The Company also instituted and has pursued more aggressive collection practices as evidenced by a lower provision for doubtful accounts in 1992. Partially offsetting these decreases were certain higher expenses, including expenses related to the Company's share in the Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) and employee related benefits.

The $47 million, or 9.9%, increase in 1991 was primarily attributable to increases in employee wages and benefits, electric production and gas distribution costs, and provision for doubtful accounts.

Other Items In 1992, federal income taxes were approximately $161 million, compared with $182 million in 1991. In 1990, these taxes amounted to $183 million, excluding the effect of the accounting change for unbilled gas revenues.

Interest expenses for 1992, 1991 and 1990 were $512 million, $524 million and $508 million, respectively. The decrease in 1992 was the result of lower interest rates, primarily achieved through refinancings.

In 1992, the Company recorded non-cash charges to income of approximately $23 million which represents the increase in the present value of the Class Settlement liability. These charges amounted to $25 million and $23 million for 1991 and 1990, respectively. For a further discussion of the Class Settlement see Note 4 of Notes to Financial Statements.

For the years 1992, 1991 and 1990, the Company recorded non-cash credits to income of $73 million, $269 million and $313 million, respectively, reflecting the RMC and related carrying charges. For a further discussion of the RMC and RMA, see Notes 2 and 3 of Notes to Financial Statements.

For the years 1992, 1991 and 1990, the Company reco non-cash charges to income of approximately $101 milli 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.

Liquidity

Cash and Revolving Credit At December 31, 1992, the Company's cash and cash equivalents amounted to approximately $309 million, compared to $298 million at December 31, 1991.

In addition, the Company has approximately $251 million available under its revolving line of credit through October 1, 1993, provided by its 1989 Revolving Credit Agreement (1989 RCA). At December 31, 1992, no amounts were outstanding under the 1989 RCA. For a further discussion of the 1989 RCA, see Note 7 of Notes to Financial Statements.

Financing Programs During 1992, the Company issued $211 million aggregate principal amount of G&R Bonds, approximately $1.3 billion aggregate principal amount of debentures and $420 million of preferred stock. The net proceeds from the sale of these securities were used to eliminate all bank debt, redeem higher-cost debt and preferred stock and to pay any related redemption cost The details respecting the Company's $2.3 billion of refinancing activities in 1992 were as follows:

Securities Issued	*Securities Redeemed*
$ 56 million G&R Bonds 7.85% Series Due 1999	$ 53 million G&R Bonds 9.75% Series Due 1999
$ 75 million G&R Bonds 8.50% Series Due 2006	$ 70 million G&R Bonds 9.625% Series Due 2006
$ 80 million G&R Bonds 7.90% Series Due 2008	$ 75 million G&R Bonds 9.20% Series Due 2008
$397 million Debentures 7.30% Series Due 1999	$319 million Debentures 10.875% Series Due 1999
$420 million Debentures 8.90% Series Due 2019	$346 million Debentures 11.375% Series Due 2019
	$ 25 million First Mortgage Bonds 9.125% Series Due 2000
$451 million Debentures 9% Series Due 2002	$446 million under the 1989 Term Loan Agreement
$363 million Preferred Stock 7.95% Series AA	$320 million Preferred Stock 10.60% Series Y
$ 57 million Preferred Stock 7.66% Series CC	$ 55 million Preferred Stock 9.80% Series S
$400 million tax-exempt securities, 7.15%, 30-year fixed annual rate	$400 million tax-exempt securities variable weekly rate

In addition to the above refinancings, the Company utili $200 million of tax-exempt securities in 1992. The net proceeds from the sale of these tax-exempt securities were used to reimburse the Company's treasury for previously incurred capital expenditures.

In addition to the conversion of $400 million of tax-exempt securities in June 1992, the Company converted $100 million of tax-exempt securities in January 1993 from a variable weekly interest rate to a 30-year fixed annual rate of 6.90%.

In January 1993, the Company issued $36 million principal amount of Debentures, 7.30% Series Due 2000, the net proceeds of which will be used in February 1993 to redeem, at the applicable redemption price, $35 million principal amount of First Mortgage Bonds, 8.20% Series R Due 1999.

In February 1993, the Company sold $142 million principal amount of Debentures, 7.50% Series Due 2007, the net proceeds of which will be used in March 1993 to redeem, at the applicable redemption prices, the following series of G&R Bonds: $50 million, 8⅝% Series Due 2006 and $85 million, 8⅝% Series Due 2007.

The Company has been able to utilize $100 million of tax-exempt securities in each of the years 1989 through 1992. In 1990, the Company was able to utilize an additional $100 million of tax-exempt securities (1991 Series A Electric Facilities Revenue Bonds) allocated for its benefit.

During the period January 1, 1993 to December 31, 1995, the Company has estimated that it will be required to seek external financing of approximately $1.4 billion, principally to refund maturing debt and secondarily to meet its operating and capital requirements. In addition, the Company intends to continue to access the capital markets to refund higher-cost debt and preferred stock, when market conditions permit.

The Company currently has debt and equity securities registered with the Securities and Exchange Commission on shelf registration statements. The sale of $615 million of these securities will be used to refund the following securities maturing in 1993: $40 million of First Mortgage Bonds, 4.40% Series M Due April 1, 1993, $375 million of Debentures, 11 3/8% Series Due April 1, 1993 and $175 million of Debentures, 11.70% Series Due November 15, 1993. The Company may also sell an additional $146 million of previously registered securities, which will be used, when market conditions permit, to refund higher-cost debt or preferred stock.

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

Capitalization

The Company's capitalization (defined as the total of long-term debt, preferred stock and common shareowners' equity) at December 31, 1992, was approximately $8.2 billion, as compared to $7.8 billion at December 31, 1991. This increase in capitalization of approximately $420 million principally reflects an increase in long-term debt and preferred stock associated with the Company's financing activities in 1992 and an increase in common shareowners' equity comprising 1992 net income of approximately $302 million reduced by common and preferred stock dividends of $254 million.

At December 31, 1991, capitalization increased by approximately $492 million from the December 31, 1990, balance of $7.3 billion. This increase in capitalization primarily reflects an increase in long-term debt associated with the Company's financing activities in 1991 and an increase in common shareowners' equity comprising 1991 net income of $306 million reduced by common and preferred stock dividends of $245 million.

At December 31, 1992 and 1991, the components of the Company's capitalization ratios were as follows:

	1992	*1991*
Long-Term Debt	64.7%	63.9%
Preferred Stock	8.8	8.8
Common Shareowners' Equity	26.5	27.3
Total	100.0%	100.0%

Capital Requirements and Capital Provided

Capital requirements and capital provided for 1992 and 1991 were as follows:

(In millions of dollars)	*1992*	*1991*
Capital Requirements		
Construction		
Electric	$ 137	$ 127
Gas	104	90
Common	27	18
Total Construction	268	235
Refundings and Dividends		
Long-term debt	1,344	1,129
Preferred stock	389	71
Preferred stock dividends	70	66
Common stock dividends	191	173
Redemption costs	159	68
Total Refundings and Dividends	2,153	1,507
Shoreham post settlement costs	228	158
Total Capital Requirements	$ 2,649	$ 1,900
Capital Provided		
(Increase) in cash	$ (11)	$ (195)
Long-term debt	1,660	1,532
Preferred stock	411	63
Financing costs	(7)	(20)
Other financing activities	6	—
Internal cash generation from operations	590	520
Total Capital Provided	$ 2,649	$ 1,900

For further information, see the Statement of Cash Flows.

For 1993, total capital requirements (excluding common stock dividends) are estimated at $1.2 billion, of which construction requirements are estimated to be $320 million, mandatory redemptions are $590 million, preferred stock sinking fund requirements are $8 million, preferred stock dividends are $57 million, and Shoreham post settlement costs are estimated at approximately $189 million. The Company intends to satisfy these capital requirements through external financing, as discussed above, and internal cash generation from operations.

Other Matters

Electric Competition, Conservation and Supply The Company is experiencing competition from cogenerators and other independent power producers located within the Company's service territory. These facilities supply electric energy to existing or new industrial and commercial customers and excess electricity is sold to the Company pursuant to the purchase requirements of the Public Utility Regulatory Policy Act of 1978 (PURPA). The Company has contracts with owners of these facilities which will provide for a total of approximately 340 megawatts (MW) of capacity by 1994, which includes the New York Power Authority's 136 MW Holtsville facility. The Company has also entered into contracts for approximately 450 MW of power from various projects on an energy-only basis.

The Company has implemented conservation and load management programs to meet Long Island's energy needs in the future. In 1992, the Company met its targeted reductions in its revised 1992 Electric Conservation and Load Management Plan, which called for a 235 MW reduction in coincident peak demand by December 31, 1992, and annualized energy savings of 454 gigawatt hours, at a budgeted cost of approximately $45.3 million. The Company anticipates that the Conservation and Load Management Plan will continue in future years to gain further reductions in system peak and energy usage.

The Company's current electric load forecasts indicate that, with continued implementation of its aggressive conservation and load management programs and with electricity provided by independent power producers and cogenerators, the Company's existing generating facilities, the Company's portion of nuclear energy generated at NMP2 and contracts for purchased power are adequate to meet the energy demands on Long Island beyond the end of the century.

Gas Competition In 1987, the Federal Energy Regulatory Commission (FERC) issued an order allowing gas pipeline companies and producers access to certain of the Company's customers for the purpose of supplying competing gas service. As of December 31, 1992, approximately 104 of the Company's former large gas customers were purchasing gas directly from gas pipeline companies and producers and arranging for its transportation through the Company's gas mains. The Company receives a fee for this transportation service which accounted for approximately $6.7 million, or 1.6%, of total gas revenues for 1992.

Clean Air Act In late 1990, significant amendments to the federal Clean Air Act were adopted. A number of electric utilities anticipate substantial increases in operating costs and capital expenditures as a result of the amendments. The Company does not expect to incur any costs to satisfy these amendments with respect to the reduction of sulfur dioxide emissions, since the Company already uses fuel with acceptably low levels of sulfur. However, the Company expects that it will incur costs to comply with additional continuous emission monitoring (CEM) requirements and for future nitrogen oxide reduction requirements that may be imposed under federal or state regulations. The Company estimates that the cost of installing CEM and nitrogen oxide control equipment, which the Company will seek to recover through rates, will be approximately $15 million and $100 million, respectively.

Accounting Pronouncements The Company will adopt the provisions of Statement of Financial Accounting Standards (SFAS) No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, during the first quarter of 1993. 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 will record an accumulated postretirement benefit obligation and corresponding regulatory asset of approximately $376 million which represents the transition obligation at December 31, 1992. Additionally, as a result of adopting SFAS No. 106, the Company's annual postretirement benefit expense will increase by approximately $44 million above the amount previously recorded under the pay-as-you-go method. This additional $44 million of non-cash postretirement benefit expense will also be accounted for as a regulatory asset. The Company believes that the PSC will permit recovery of these regulatory assets through rates. For a further discussion of SFAS No. 106, including the recoverability of these regulatory assets, see Note 8 of Notes to Financial Statements.

The Company will adopt SFAS No. 109, Accounting for Income Taxes, during the first quarter of 1993. 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 and the equity component of AFC. 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 Company estimates that had it adopted SFAS No. 109 at December 31, 1992, the Company would have recorded an accumulated deferred tax liability and a corresponding regulatory asset of approximately $1.2 billion. The impact of SFAS No. 109 on the Statement of Income is not expected to be material. For a further discussion of SFAS No. 109, see Note 1 of Notes to Financial Statements.

Selected Financial Data

Additional financial information for the last five years is provided in Tables 1 through 11 of Selected Financial Data. Information with regard to the Company's business segments for the last three years is provided in Note 11 of Notes to Financial Statements.

Statement of Income

(In thousands of dollars except per share amounts)

For year ended December 31	1992	1991	1990
Revenues			
Electric	$ 2,194,632	$ 2,196,568	$ 2,095,660
Gas	427,207	351,161	361,242
Total Revenues	2,621,839	2,547,729	2,456,902
Expenses			
Operations — fuel and purchased power	741,784	768,702	786,999
Operations — other	372,209	375,267	340,518
Maintenance	125,736	147,492	135,291
Depreciation and amortization	119,137	118,955	110,884
Base financial component amortization	100,971	100,971	100,971
Regulatory liability component amortization	(88,573)	(88,573)	(88,573)
Other regulatory amortizations	(22,072)	8,666	14,427
Rate moderation component	(30,444)	(228,572)	(297,214)
Operating taxes	388,988	388,380	370,317
Federal income tax — current	530	515	3,638
Federal income tax — deferred and other	172,468	168,937	177,014
Total Expenses	1,880,734	1,760,740	1,654,272
Operating Income	741,105	786,989	802,630
Other Income and (Deductions)			
Allowance for other funds used during construction	4,725	2,202	2,940
Rate moderation component carrying charges	42,837	40,456	15,683
Other income and deductions, net	28,832	33,783	27,218
Class Settlement	(22,541)	(25,467)	(22,574)
Federal income tax (charge) — deferred and other	12,036	(12,201)	(2,629)
Total Other Income and (Deductions)	65,889	38,773	20,638
Income Before Interest Charges and Cumulative Effect of Accounting Change	806,994	825,762	823,268
Interest Charges and (Credits)			
Interest on long-term debt	450,621	472,974	467,700
Other interest	61,785	50,842	40,559
Allowance for borrowed funds used during construction	(7,386)	(3,592)	(4,628)
Total Interest Charges and (Credits)	505,020	520,224	503,631
Income Before Cumulative Effect of Accounting Change	301,974	305,538	319,637
Cumulative Effect of Accounting Change for Unbilled Gas Revenues (net of applicable taxes of $6,017)	—	—	11,680
Net Income	301,974	305,538	331,317
Preferred stock dividend requirements	63,954	66,394	68,161
Earnings for Common Stock	$ 238,020	$ 239,144	$ 263,156
Average Common Shares Outstanding (000)	111,439	111,348	111,290
Earnings per Common Share			
Before cumulative effect of accounting change	$ 2.14	$ 2.15	$ 2.26
Cumulative effect of accounting change	—	—	.10
Earnings per Common Share	$ 2.14	$ 2.15	$ 2.36
Dividends Declared per Common Share	$ 1.72	$ 1.60	$ 1.25

See Notes to Financial Statements.

Balance Sheet

Assets		(In thousands of dollars)
At December 31	*1992*	
Utility Plant		
Electric	$ 3,429,803	$ 3,323,008
Gas	760,635	666,904
Common	172,703	157,495
Construction work in progress	161,663	157,511
Nuclear fuel in process and in reactor	19,216	29,818
	4,544,020	4,334,736
Less — Accumulated depreciation and amortization	1,382,872	1,332,003
Total Net Utility Plant	3,161,148	3,002,733
Regulatory Asset		
Base financial component (less accumulated amortization of $353,398 and $252,427)	3,685,432	3,786,403
Nonutility Property and Other Investments	20,730	9,788
Current Assets		
Cash and cash equivalents	309,485	298,098
Special deposits	23,683	23,207
Customer accounts receivable (less allowance for doubtful accounts of $24,375 and $26,935)	208,049	210,525
Other accounts receivable	6,937	6,515
Accrued unbilled revenues	143,172	136,565
Materials and supplies at average cost	86,482	86,863
Fuel oil at average cost	51,702	44,[illegible]
Gas in storage at average cost	47,002	43,[illegible]
Prepayments and other current assets	40,402	34,8[illegible]
Total Current Assets	916,914	884,017
Deferred Charges		
Rate moderation component	651,657	602,053
Shoreham post settlement costs	586,045	378,386
Unamortized cost of issuing securities	380,267	227,713
Shoreham nuclear fuel	77,629	79,760
Accumulated deferred income taxes	511,898	439,235
Other	256,904	133,213
Total Deferred Charges	2,464,400	1,860,360
Total Assets	$ 10,248,624	$ 9,543,301

See Notes to Financial Statements.

Capitalization and Liabilities

December 31	1992	1991
	(In thousands of dollars)	
Capitalization		
Long-term debt	$ 4,755,733	$ 5,001,016
Unamortized premium and (discount) on debt	(14,731)	(14,850)
	4,741,002	4,986,166
Preferred stock — redemption required	557,900	524,912
Preferred stock — no redemption required	154,276	154,371
Total Preferred Stock	712,176	679,283
Common stock	558,002	556,825
Premium on capital stock	998,089	993,509
Capital stock expense	(39,304)	(40,216)
Retained earnings	667,988	620,373
Total Common Shareowners' Equity	2,184,775	2,130,491
Total Capitalization	7,637,953	7,795,940
Current Liabilities		
Current maturities of long-term debt	590,000	10,000
Current redemption requirements of preferred stock	8,200	10,616
Accounts payable and accrued expenses	286,102	223,589
Accrued taxes (including federal income taxes of $27,100 and $27,693)	67,525	60,174
Accrued interest	131,179	85,565
Dividends payable	53,966	60,287
Class Settlement	30,000	20,000
Customer deposits	24,815	22,664
Total Current Liabilities	1,191,787	492,895
Deferred Credits		
1989 Settlement credits	164,294	173,507
Class Settlement	167,066	173,564
Accumulated deferred income taxes	970,373	816,053
Other	110,341	84,035
Total Deferred Credits	1,412,074	1,247,159
Reserves for Claims, Damages, Pensions and Benefits	6,810	7,307
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 10,248,624	$ 9,543,301

See Notes to Financial Statements.

Shareowners' Equity

(In thousands of dolla

Statement of Retained Earnings	1992	1991	1[illegible]
Balance at January 1	$ 620,373	$ 560,405	$ 436,69[illegible]
Net income for the year	301,974	305,538	331,317
	922,347	865,943	768,007
Deductions			
Cash dividends declared on preferred stock	62,387	67,261	68,218
Cash dividends declared on common stock	191,693	178,169	139,128
Capital stock expense	279	140	256
Balance at December 31	$ 667,988	$ 620,373	$ 560,405

Preferred Stock *(In thousands of dollars)*

At December 31	Call Price Per Share December 31, 1992	Call Price Per Share Final	1992	1991	1990
Par Value $100 per Share, Cumulative					
Shares authorized			7,000,000	7,000,000	7,000,000
Shares issued and outstanding			2,353,757	2,438,993	2,528,400
5.00% Series B	$101.00	$101.00	$ 10,000	$ 10,000	$ 10,000
4.25% Series D	102.00	102.00	7,000	7,000	7,000
4.35% Series E	102.00	102.00	20,000	20,000	20,000
4.35% Series F	102.00	102.00	5,000	5,000	5,000
5 1/8% Series H	102.00	102.00	20,000	20,000	20,000
5 3/4% Series I Convertible	100.00	100.00	2,276	2,371	2,674
8.12% Series J	101.00	101.00	25,000	25,000	25,000
8.30% Series K	103.29	103.29	30,000	30,000	30,000
7.40% Series L*	103.22	100.00	20,300	21,350	22,4[illegible]
8.40% Series M*	103.36	100.00	23,800	25,200	26,[illegible]
8.50% Series R*	101.00	100.00	15,000	22,500	26,25[illegible]
9.80% Series S*	—	—	—	55,478	57,916
7.66% Series CC*	**	100.00	57,000	—	—
Total Par Value $100			$ 235,376	$ 243,899	$ 252,840
Par Value $25 per Share, Cumulative					
Shares authorized			30,000,000	30,000,000	30,000,000
Shares issued and outstanding			19,400,000	17,840,000	17,720,000
$2.47 Series O*	$ 25.25	$ 25.25	$ 22,000	$ 26,000	$ 28,000
$2.43 Series P	27.75	27.75	35,000	35,000	35,000
$3.31 Series T*	—	—	—	—	60,000
$2.65 Series Y*	—	—	—	320,000	320,000
$2.35 Series Z*	27.35	25.00	65,000	65,000	—
7.95% Series AA*	**	25.00	363,000	—	—
Total Par Value $25			$ 485,000	$ 446,000	$ 443,000
Less — Sinking fund requirements			$ 8,200	$ 10,616	$ 13,616
Total Preferred Stock			$ 712,176	$ 679,283	$ 682,224

Common Stock *(In thousands of dollars)*

At December 31	1992	1991	1990
Par Value $5 per Share			
Shares authorized	150,000,000	150,000,000	150,000,000
Shares issued and outstanding	111,600,376	111,365,056	111,324,081
Increase in shares outstanding	235,320	40,975	74,613
Increase in $5 par value	$ 1,177	$ 205	$ 3[illegible]
Increase in premium on capital stock	$ 4,493	$ 614	$ [illegible]
Decrease in capital stock expense	$ 912	$ 2,460	$ 24[illegible]

**Redemption required, see Note 6. **Not callable at December 31, 1992.*
The aggregate fair value of redeemable preferred stock at December 31, 1992 amounted to $581,984 compared to its carrying amount of $566,100.
See Notes to Financial Statements.

Statement of Cash Flows

(In thousands of dollars)

Year ended December 31	1992	1991	1990
Operating Activities			
Net Income	$ 301,974	$ 305,538	$ 331,317
Adjustments to reconcile net income to net cash provided by operating activities			
Cumulative effect of accounting change for unbilled gas revenues	—	—	(11,680)
Depreciation and amortization	119,137	118,955	110,884
Fuel moderation component	—	34,025	3,804
Provision for doubtful accounts	16,329	35,431	30,097
Base financial component amortization	100,971	100,971	100,971
Regulatory liability component amortization	(88,573)	(88,573)	(88,573)
Other regulatory amortizations	(22,072)	8,666	14,427
Rate moderation component	(30,444)	(228,572)	(297,214)
Rate moderation component carrying charges	(42,837)	(40,456)	(15,683)
Class Settlement	22,541	25,467	22,574
Amortization of cost of issuing and redeeming securities	41,204	27,456	23,648
Federal income taxes — deferred and other	160,432	181,138	179,643
Allowance for other funds used during construction	(4,725)	(2,202)	(2,940)
Other	699	38,068	15,234
Changes in operating assets and liabilities			
Accounts receivable	(14,275)	(26,045)	(22,463)
Accrued unbilled revenues	(6,607)	2,352	30,748
Materials and supplies, fuel oil and gas in storage	(10,933)	28,217	(48,040)
Prepayments and other current assets	(5,548)	(1,035)	23,752
Accounts payable and accrued expenses	62,513	34,560	2,345
Class Settlement	—	—	(20,129)
Accrued taxes	7,351	3,926	(42,187)
Other	(17,073)	(37,459)	(19,477)
Net Cash Provided by Operating Activities	590,064	520,428	321,058
Investing Activities			
Construction and nuclear fuel expenditures	(268,179)	(235,349)	(229,525)
Shoreham post settlement costs	(227,658)	(158,432)	(152,675)
Other	(1,484)	(3,923)	81
Net Cash Used in Investing Activities	(497,321)	(397,704)	(382,119)
Financing Activities			
Proceeds from issuance of long-term debt	1,659,928	1,532,247	112,319
Redemption of long-term debt	(1,344,283)	(1,129,000)	(82,000)
Proceeds from sale of preferred stock	411,373	63,130	—
Redemption of preferred stock	(389,428)	(70,638)	(13,659)
Preferred stock dividends paid	(69,923)	(65,838)	(68,046)
Common stock dividends paid	(190,477)	(172,584)	(125,192)
Cost of issuing and redeeming securities	(166,066)	(88,586)	(1,327)
Other	7,520	3,707	1,598
Net Cash (Used in) Provided by Financing Activities	(81,356)	72,438	(176,307)
Net Increase (Decrease) in Cash and Cash Equivalents	$ 11,387	$ 195,162	$ (237,368)
Cash and cash equivalents at beginning of year	$ 298,098	$ 102,936	$ 340,304
Net increase (decrease) in cash and cash equivalents	11,387	195,162	(237,368)
Cash and Cash Equivalents at End of Year	$ 309,485	$ 298,098	$ 102,936
Interest paid, before reduction for the allowance for borrowed funds used during construction	$ 424,842	$ 477,240	$ 479,278
Federal income taxes paid	$ 2,100	$ 1,650	$ 900
Federal income taxes refunded	$ 1,566	$ 642	$ 23,588

See 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 that portion of construction work in progress which is not included in the Company's rate base. The average annual AFC rate, without giving effect to compounding, was 9.98%, 10.74% and 11.03% for the years 1992, 1991 and 1990, 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 3.2%, 3.3% and 3.2% of respective average depreciable plant costs for the years 1992, 1991 and 1990. Depreciation for gas properties was equivalent to approximately 2.6%, 2.9% and 2.8% of respective average depreciable plant costs for the years 1992, 1991 and 1990.

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, the Company recorded a regulatory asset known as the Financial Resource Asset (FRA), 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.

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

Effective January 1, 1990, the Company adopted the full accrual method for unbilled gas revenues. Previously, unbilled gas revenues were recognized only for customers billed on a bi-monthly cycle basis for the month in which they were normally not billed. This change better matches revenues and expenses and provides consistency with the Company's revenue recognition method for electric revenues. The cumulative effect of this change at January 1, 1990 was $11.7 million, net of tax effects, or $.10 per share and had been included in net income for the year ended December 31, 1990. The effect of this change on income before the cumulative effect of accounting change and on earnings for common stock for the year ended December 31, 1990 was not material.

Fuel Cost Adjustments The Company's electric and gas tariffs include fuel cost adjustment (FCA) clauses which provide for 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 adjustments, net of tax effects, 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. The Company collects the higher of actual electric fuel costs or base electric fuel costs, pursuant to the RMA.

Effective December 1, 1991, the electric rate order discussed in Note 3 authorized the adoption of a partial pass-through fuel cost incentive plan which includes a mechanism that compares, on a monthly basis, the Company's actual cost to produce electric energy against a targeted fuel value. The incentive measures the Company's ability to purchase fuel at the lowest possible cost, to purchase energy economically from other power suppliers and to operate its generating plants at optimum efficiency. The shareowners are allocated 40% of the impact between actual fuel costs and targeted fuel values up to a maximum benefit or penalty of 20 basis points of the allowed return on common equity. The shareowners' portion of these impacts are being deferred on a monthly basis. The accumulated net deferral will be recovered or returned, through the FCA, over a twelve-month period in the following rate year. For a further discussion of the partial pass-through fuel cost incentive, see Note 3.

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 the redeemed or new issues. Capital stock expense related to that portion of preferred stock that is required to be redeemed is written-off as an adjustment to retained earnings upon redemption unless the preferred stock is redeemed below par value. In that case, any resulting gain, net of the related capital stock expense, is recorded as additional premium on capital stock. 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.

Federal Income Taxes 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. 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.

For ratemaking purposes, 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. Accumulated deferred investment tax credits are amortized ratably over the lives of the related properties.

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.

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes 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 and the equity component of AFC. 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 Company estimates that had it adopted SFAS No. 109 at December 31, 1992, the Company would have recorded an accumulated deferred tax liability and a corresponding regulatory asset of approximately $1.2 billion. The Company will adopt SFAS No. 109 during the first quarter of 1993 and does not expect a material impact on the Statement of Income.

Reserves for Claims, Damages, Pensions and Benefits Losses arising from claims against the Company are partially self-insured. Extraordinary storm losses are partially self-insured up to $5 million until March 1, 1993, at which time the Company will bear a greater portion of these costs. Amounts provided are credited to the reserves based upon experience, risk of loss, actuarial estimates and/or specific orders of the PSC.

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

Note 2. The 1989 Settlement

On February 28, 1989, the Company and the State of New York (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.

The 1989 Settlement recites the intention of the parties that the Company shall be returned to investment grade financial condition and that the Company and the State of New York anticipate that the PSC shall ensure that the future impacts on rates are to be minimized to the maximum extent practicable. It is the Company's position that these objectives will continue to be achieved, in part, through the continued receipt of adequate and timely rate relief.

Upon the effectiveness of the 1989 Settlement, the Company simultaneously recorded on its Balance Sheet the retirement of its investment of approximately $4.2 billion in Shoreham and Bokum Resources Corporation (Bokum) and the establishment of the FRA.

The BFC, a component of the FRA, as initially established, represents the present value of the future net-after-tax cash flows which the RMA provided the Company for its financial recovery. The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis beginning July 1, 1989. At December 31, 1992 and 1991, the unamortized balance of the BFC was approximately $3.7 billion and $3.8 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, which has provided the Company with a substantial amount of non-cash earnings over the last several years, is based upon forecasted data filed in connection with the RMA. The RMA was designed to provide rate increases sufficient to recover the RMC within a ten-year period. 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. Prior to December 1, 1991, the RMC was adjusted to reflect actual property taxes, cost of asbestos removal, interest expense, energy conservation and load management program costs, costs to provide added electric system reliability and inflation.

The RMC balance, which was $652 million and $602 million at December 31, 1992 and 1991, respectively, has 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, has been deferred. The RMC balance will subsequently decrease and is expected to be fully amortized by November 30, 1999, as deferred revenue requirements are recovered.

The PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP), discussed in Note 3, effective for each of the three rate years in the period beginning December 1, 1991. Although the LRPP provides for slightly lower annual electric rate increases than originally anticipated in the 1989 Settlement, the Company believes that it will still fully recover the RMC over the ten-year period principally as a result of changes in the original assumptions. The revenues assumed by the LRPP are adequate to provide the Company with recovery of its revenue requirements under conventional ratemaking and recovery of the RMC balance over the remainder of the ten-year period. However, actual revenues may differ fro[m] those assumed for this period. The original assumptions underlying the RMA included projections of future revenues, operating expenses and required rates of return. Since then, the Company has experienced interest rates, non-Shoreham property taxes and fuel expenses that are lower than those originally anticipated. As a result, amounts deferred in the RMC have been less than expected. In addition, as a result of the Company's improved credit ratings and an overall decline in the cost of money in the financial marketplace, the PSC provided the Company in the LRPP with a lower rate of return on common equity than that initially provided for in the RMA. This lower rate of return, which will be in effect for the three years associated with the LRPP, results in a lower RMC balance than had been anticipated in the 1989 Settlement.

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 tax benefit arising from the abandonment loss deduction has been offset against the corresponding regulatory liability [on] the Company's Balance Sheet. This tax benefit could not have been fully recognized under GAAP were it not for the fact that its recovery is assured under the 1989 Settlement through the regulatory liability offset.

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 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 $164 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 rate filing, the PSC approved the 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 are 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 including: (a) the recovery of the BFC; (b) the recovery of the RMC in approximately ten years; (c) the Company's return to investment grade financial condition; and (d) the Company's receipt of adequate and timely rate relief. 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 and operations and maintenance expenses, and the application of an inflation index to other expenses for the rate years beginning December 1, 1992 and 1993.

The deferred balances resulting from the net margin, property taxes, interest expense and wage rates will be netted at the end of each rate year. The LRPP established a band whereby the first $15 million of the total net deferrals will be 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. The total net deferrals in excess of $15 million will be refunded to or recovered from the ratepayers in the following twelve-month period beginning in the second quarter of each year. For the rate year ended November 30, 1992, the total net deferrals in excess of $15 million, to be recovered from the ratepayers, amounted to approximately $29.5 million.

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 performance plan, a DSM program, a time-of-use program and a partial pass-through fuel cost incentive plan, discussed in Note 1. The incentives and/or penalties related to the customer service performance plan and the time-of-use program are determined on a monthly basis during the rate year. The total amounts deferred at the end of each rate year will be refunded to or recovered from the ratepayers through the FCA in the following twelve-month period beginning in the second quarter of each year. The incentives earned from the DSM program are collected in rates, on a monthly basis, through the FCA. For the rate year ended November 30, 1992, the Company earned a total of approximately 23 basis points, or $4.3 million, net of tax effects, based upon its performance within these programs.

For the rate year ended November 30, 1992, the Company earned $16.2 million, net of tax effects, in excess of its allowed rate of return on common equity which, in accordance with the LRPP, was shared equally between ratepayers (by a reduction to the RMC) and shareowners. These excess earnings were generated as a result of a reduction in operating expenses and the effect of a decrease in capital expenditures included in rate base. Prior to December 1, 1991, the RMA provided that earned returns on common equity in excess of targeted allowed rates of return, as adjusted, 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. The Company did not earn in excess of its allowed rate of return for the rate year ended November 30, 1990.

To assist in recovering the RMC within a ten-year period 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 1992, the Company applied a total of approximately $22.5 million of various deferred ratepayer benefits to the RMC including the ratepayers portion of the excess earnings for the rate year ended November 30, 1992. In December 1991, the Company applied approximately $57.6 million of previously deferred credits and related carrying charges for amounts collected in excess of actual fuel costs and other miscellaneous deferred credits as a reduction to the RMC.

Gas In November 1992, the PSC approved a gas rate increase of 7.1%, or $35.7 million annually, which became effective on December 1, 1992. The gas rate decision provides for an 11.0% allowed return on common equity for the rate year beginning December 1, 1992.

On December 31, 1992, the Company filed an application with the PSC seeking gas rate relief for the three rate years in the period beginning December 1, 1993. The Company has requested a gas rate increase of 6.7%, or $37.7 million in additional revenues to become effective for the first rate year under this filing. The Company's filing also includes a proposed methodology for determining rate increases, not to exceed approximately $30 million annually, for the subsequent second and third rate years. This filing reflects the Company's latest projections of capital expenditures, operations and maintenance expenses and the continued expansion of its gas business.

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 beginning June 1, 1990. The reductions required for the first three years have already been reflected in rates. The reductions in each subsequent twelve-month period are as follows:

June 1993	$30 million
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 millio and simultaneously recorded a charge to income (net of ta 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. Because the reductions of the liability are greater in the later years, the current present value calculations result in an increase in total liability despite the reductions in the total amount due. Beginning sometime in 1993, the amount of the total remaining Class Settlement liability will begin to decrease as the monthly reductions of the liability exceed the incremental increases in the present value. 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 balance of the Class Settlement period. The amounts recorded on the Statement of Income for 1992, 1991 and 1990 of approximately $23 million, $25 million and $23 million, respectively, represent the increase in present value of the Class Settlement liability.

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, 1992, the Company's net utility plant investment in NMP2 was $776 million, net of accumulated depreciation of $97 million, which is included in the Company's rate base. Output of NMP2, which had an operating capability of 1,080 megawatts in 1992, is shared in the same proportions as the cotenants' respective ownership interests. NMPC has determined that the operating capability of NMP2, effective January 1, 1993, is 1,047 megawatts. 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, the Company's share of the decommissioning costs for NMP2 is estimated to be $37 million (in 1989 dollars) assuming that decommissioning will commence in 2027 or $237 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, 1992 was $5.4 million. Amounts collected by the Company for the decommissioning of the contaminated portion of the NMP2 plant, which approximate 84% of total decommissioning costs, are held in an independent decommissioning trust fund. This fund complies with regulations issued by the Nuclear Regulatory Commission (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. The Internal Revenue Service (IRS) has ruled that the Company's decommissioning trust meets the requirements of a qualified fund under applicable provisions of the federal income tax law. This IRS ruling allows the Company's contributions to the decommissioning trust to be deductible for income tax purposes for the tax year in which they are made.

Note 6. Capital Stock

Preferred Stock Redemption of certain series of preferred stock is effected through the operation of various sinking fund provisions. The aggregate par value of preferred stock required to be redeemed in each of the years 1993 through 1996 is $8.2 million and in 1997 is $4.5 million. Dividends on preferred stock are paid in preference to dividends on common stock or any other stock ranking junior to preferred stock.

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, 1992, 1,834,289 shares were reserved for sale through the Company's Employee Stock Purchase Plan, 6,620,755 shares were committed to the Automatic Dividend Reinvestment Plan (ADRP) and 132,694 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 and 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 and $957 million at December 31, 1992 and 1991, respectively. The annual First Mortgage depreciation fund and sinking fund requirements for 1992, due not later than June 30, 1993, are estimated at $194 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 1992, due not later than June 30, 1993, is estimated at $27 million. The Company expects to satisfy this requirement with retired G&R Bonds.

Third Mortgage/1989 Term Loan Agreement In November 1992, the Company used the net proceeds from the issuance of $451 million principal amount of debentures to repay the then outstanding 1989 Term Loan Agreement which had been secured by the Third Mortgage. The Third Mortgage has been discharged as a result of the repayment of the 1989 Term Loan Agreement.

Fourth Mortgage In December 1992, the Company satisfied the Fourth Mortgage which had secured $85 million of the Company's obligations under the letters of credit then supporting the 1985 Pollution Control Revenue Bonds (1985 PCRBs). The 1985 PCRBs are presently supported by unsecured letters of credit discussed below under the heading Authority Financing Notes.

1989 Revolving Credit Agreement The Company has an estimated $251 million available to it through October 1, 1993, 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 has, with the approval of the NRC, dedicated $49 million of the 1989 RCA sufficient to cover estimated, not yet incurred, costs attributable to the decommissioning of Shoreham. As of December 31, 1992, LIPA was projecting, based on current information, that the Shoreham decommissioning costs would total $160 million. The Company has provided LIPA with funds aggregating approximately $111 million for decommissioning costs incurred to date and for decommissioning costs expected to be incurred during the first quarter of 1993. Actual decommissioning costs may differ from LIPA's current estimate. 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, 1992, 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: (a) the Adjusted Certificate of Deposit Rate which is a rate based on the certificate of deposit rates of certain of the lending banks, (b) the Base Rate which is generally a rate based on Citibank, N.A.'s prime rate and (c) 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 ba[illegible] of the Company's request delivered to the lending banks prior to April 1 in each year.

Debentures On January 19, 1993, the Company issued $36 million principal amount of Debentures, 7.30% Series Due 2000. The net proceeds from the issuance of these debentures will be used in February 1993 to redeem, at the applicable redemption price, $35 million principal amount of First Mortgage Bonds, 8.20% Series R Due 1999.

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, 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 Company has $400 million of EFRBs that were converted in June 1992 from a variable weekly interest rate to a fixed annual rate of 7.15% and $100 million of EFRBs that were converted in January 1993 from a variable weekly interest rate to a fixed annual rate of 6.90%. Letters of credit supporting these EFRBs, by their terms, were terminated upon the conversion to a fixed interest rate.

The 1985 PCRBs are supported by letters of credit pursuant to which the letter of credit bank has agreed to pay the principal, interest and premium on the tendered 1985 PCRBs, in the aggregate, up to approximately $163 million in the event of default. The obligation of the Company to reimburse the letter of credit bank is unsecured. These letters of credit expire on March 16, 1996, 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 1985 PCRBs must be redeemed unless the Company purchases the 1985 PCRBs in lieu of redemption and subsequently remarkets them. Prior to December 16, 1992, the letters of credit supporting the 1985 PCRBs were partially secured by the Fourth Mortgage in the amount of $85 million.

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, 1992:

(In thousands of dollars)

	Fair Value	*Carrying Amount*
First Mortgage Bonds	$ 397,971	$ 400,000
General and Refunding Bonds	1,891,842	1,801,[illegible]
Debentures	2,523,721	2,428,[illegible]
Authority Financing Notes	729,610	716,6[illegible]
Total Long-Term Debt	$5,543,144	$5,345,733

(In thousands of dollars)

Long-Term Debt *at December 31*

	Maturity	Interest Rate	Series	1992	1991
First Mortgage Bonds *(excludes Pledged Bonds)*					
	April 1, 1993	4.40%	M	$ 40,000	$ 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	35,000
	September 1, 2000	9 1/8%	S	—	25,000
	April 1, 2001	7 1/4%	U	40,000	40,000
	December 1, 2001	7 1/2%	V	50,000	50,000
	September 1, 2002	7 5/8%	W	50,000	50,000
	December 1, 2003	8 1/8%	X	60,000	60,000
Total First Mortgage Bonds				400,000	425,000
General and Refunding Bonds					
	May 1, 1996	8 3/4%		415,000	415,000
	February 15, 1997	8 3/4%		250,000	250,000
	March 1, 1999	9.75%		—	63,000
	May 15, 1999	7.85%		56,000	—
	May 15, 2006	8.50%		75,000	—
	June 1, 2006	9 5/8%		—	70,000
	December 1, 2006	8 5/8%		50,000	50,000
	May 1, 2007	8 5/8%		85,000	85,000
	April 1, 2008	9.20%		—	75,000
	July 15, 2008	7.90%		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				1,801,000	1,798,000
Third Mortgage/1989 Term Loan Agreement				—	446,341
Debentures					
	April 1, 1993	11 3/8%		375,000	375,000
	November 15, 1993	11.70%		175,000	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	350,000
	July 15, 1999	7.30%		397,000	—
	June 15, 2019	11.375%		4,513	350,000
	July 15, 2019	8.90%		420,000	—
	November 1, 2022	9%		451,000	—
Total Debentures				2,428,058	1,825,000
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	4%**	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	—
	August 1, 2022	3.95%***	1992 C	50,000	—
	August 1, 2022	4%***	1992 D	50,000	—
Industrial Development Revenue Bonds					
	December 1, 2006	7.5%	1976A,B	2,000	2,000
Total Authority Financing Notes				716,675	516,675
Total Long-Term Debt				5,345,733	5,011,016
Less — Current maturities				590,000	10,000
Total Long-Term Debt Less Current Maturities				$4,755,733	$5,001,016

**Tendered every three years, next tender October 1994.* ***Tendered annually on March 1.*

****Converted to a fixed annual rate of 6.90% from a variable weekly rate on January 21, 1993.*

Long-term debt due in the next five years is $590,000 (1993), $600,000 (1994), $25,000 (1995), $455,000 (1996) and $286,000 (1997).

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.

For service before January 1, 1992, pension benefits are determined based on the greater of an accrued benefit as of December 31, 1991, or applying a moving five-year average to a certain percentage per year of service. For service after January 1, 1992, pension benefits are established by crediting the employee with an amount determined using the base salary for each year the employee is a participant in the plan. This change in the pension benefits calculation resulted in an increase of approximately $70 million in the actuarial present value of projected benefit obligation. Employees are vested in the pension plan after five years of service with the Company.

The Primary Plan's funded status and amounts recognized on the Balance Sheet at December 31, 1992 and 1991 were as follows:

(In thousands of dollars)	*1992*	*1991*
Actuarial present value of benefit obligation		
Vested benefits	$ 453,201	$ 375,326
Nonvested benefits	4,326	5,315
Accumulated benefit obligation	$ 457,527	$ 380,641
Plan assets at fair value	$ 556,399	$ 519,816
Actuarial present value of projected benefit obligation	536,818	446,718
Projected benefit obligation less than plan assets	19,581	73,098
Unrecognized January 1, net obligations	98,147	33,113
Unrecognized net gain	(128,218)	(114,389)
Net accrued pension cost	$ (10,490)	$ (8,178)

Periodic pension cost for 1992, 1991 and 1990 for the Primary Plan included the following components:

(In thousands of dollars)	*1992*	*1991*	*1990*
Service cost—benefits earned during the period	$ 13,661	$ 14,323	$ 12,720
Interest cost on projected benefit obligation and service cost	39,574	33,698	32,264
Actual return on plan assets	(47,156)	(63,875)	(23,121)
Net amortization and deferral	12,849	33,569	(5,449)
Net periodic pension cost	$ 18,928	$ 17,715	$ 16,414

Assumptions used in accounting for the Primary Plan were:

	1992	*1991*	*1990*
Discount rate	7.75%	7.75%	7.25%
Rate of future compensation increases	5.5%	5.5%	6.0%
Long-term rate of return on assets	7.5%	7.0%	7.0%

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

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 $685,000, $675,000 and $561,000 and was recognized as an expense in 1992, 1991 and 1990, 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 $133,000, $101,000 and $99,000 and was recognized as an expense in 1992, 1991 and 1990, 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. The cost of providing these benefits on a pay-as-you-go method was $38,044,000, $37,312,000 and $29,410,000 for 1992, 1991 and 1990, respectively, and were recognized as an expense as benefits and premiums were paid. The cost of providing these benefits for approximately 2,200 retirees is not separable from the cost of providing benefits for approximately 6,200 active employees for the years 1990 through 1992.

In December 1990, the FASB issued 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.

The Company will adopt the provisions of SFAS No. 106 during the first quarter of 1993 and record an accumulated postretirement benefit obligation and a corresponding regulatory asset of approximately $376 million. This regulatory asset will be amortized and recovered in rates over a twenty-year period. Additionally, as a result of adopting SFAS No. 106, the Company's annual postretirement benefit expense will increase approximately $44 million above the amount previously recorded under the pay-as-you-go method.

In 1992, the PSC staff issued a proposed generic accounting order which proposes that the effects of implementing SFAS No. 106 be phased into rates. The PSC proposes that the difference between the postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and the postretirement benefit expense reflected in rates will be deferred and accumulated as a regulatory asset. 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.

In November 1992, the FASB issued SFAS No. 112, Employer's Accounting for Postemployment Benefits. SFAS No. 112 establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement. SFAS No. 112 requires employers to recognize the obligation to provide postemployment benefits if the following conditions are met: the obligation is attributable to employees services already rendered, employee rights to those benefits are accumulated or vested, payment is probable and the amount of the benefit is reasonably estimated. The Company has not yet evaluated the effect of implementing SFAS No. 112 on its financial condition and results of operations. The Company believes it will be permitted to recover these costs through rates. The Company must adopt SFAS No. 112 by January 1, 1994, and does not expect to do so prior to that date.

Note 9. Commitments and 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 offsite 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.

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.

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 Shoreham 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 $74 million per nuclear incident in any one year at any nuclear unit, but not in excess of approximately $12 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 $7.4 billion.

Note 10. Federal Income Taxes

On April 17, 1989, the Company received a private letter ruling from the IRS which stated that the Company would be entitled, for federal income tax purposes, to an abandonment loss deduction in connection with Shoreham, upon effectiveness of the 1989 Settlement. The Company claimed an abandonment loss deduction on its 1989 federal income tax return of approximately $1.8 billion. The Company's net operating loss carryforward is estimated to be approximately $2.3 billion at December 31, 1992.

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 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 this matter 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 Shoreham abandonment loss deduction and thus any impact would not have a material effect on the Company's financial condition or cash flows.

The amount of investment tax credit (ITC) carryforward fo financial statement purposes after 1992 is approximately $206 million. The Revenue Agents have proposed ITC adjustments which, if sustained, would reduce the Company's carryforward by approximately $96 million. These 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 other taxable year.

The Company has not provided deferred taxes on approximately $500 million of various other deductions and depreciation method differences for property placed in service prior to 1981 which, in conformity with the ratemaking practices of the PSC, have been flowed through. These various other flow-through tax deductions, which were deductible currently for tax purposes but capitalized for accounting and ratemaking purposes, include certain taxes, a portion of AFC, pensions and certain other employee benefits. See Note 1 with respect to a change in the method of accounting for income taxes which the Company will adopt during the first quarter of 1993.

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)

	1992		*1991*		*1990*	
	Amount	*% of Pre-tax Income*	*Amount*	*% of Pre-tax Income*	*Amount*	*% of Pre-tax Income*
Federal income tax, per Statement of Income						
Current	$ 530		$ 515		$ 3,638	
Deferred and other (see Note 1)						
1989 Settlement						
Shoreham property	3,806		10,677		3,239	
Bokum Resources Corporation	—		20,400		—	
Rate moderation component	10,351		77,715		101,053	
Other 1989 Settlement items	(5,499)		(13,638)		(13,577)	
Shoreham post settlement costs	60,125		50,375		61,475	
Contractor litigation settlement	—		(18,758)		—	
Class Settlement	(1,190)		(2,038)		(534)	
Interest capitalized	(2,100)		(2,562)		(3,220)	
Mortgage recording tax	(222)		4,653		(589)	
Accelerated tax depreciation	35,951		30,447		33,342	
Call premiums	35,441		18,496		(3,111)	
Fuel cost adjustments	8,747		(3,289)		4,879	
Capitalized overheads	—		180		2,287	
Retired debt costs	2,645		9,185		—	
Ratemaking and performance plan	17,680		(371)		—	
Lien date property taxes	(6,161)		—		—	
Other items, net	858		(334)		(5,601)	
Total Deferred and Other	160,432		181,138		179,643	
Total federal income tax expense	160,962		181,653		183,281	
Income before cumulative effect of accounting change	301,974		305,538		319,637	
Income Before Cumulative Effect of Accounting Change and Income Taxes	$ 462,936		$ 487,191		$ 502,918	
Statutory federal income tax	$ 157,398	34.0%	$ 165,645	34.0%	$ 170,992	34.0%
Additions (reductions) in federal income tax resulting from:						
1989 Settlement						
Shoreham property	4,003	0.9	4,003	0.8	4,035	0.8
Allowance for funds used during construction	(4,118)	(0.9)	(1,310)	(0.3)	(2,573)	(0.5)
Lien date property taxes	—	—	277	0.1	(8,757)	(1.8)
Tax credits	(6,586)	(1.4)	(2,980)	(0.6)	1,537	0.3
Excess of book depreciation over tax depreciation	12,193	2.6	13,108	2.7	11,987	2.4
Interest capitalized	2,947	0.6	4,232	0.9	6,031	1.2
Other items, net	(4,875)	(1.0)	(1,322)	(0.3)	29	0.0
Total Federal Income Tax Expense	$ 160,962	34.8%	$ 181,653	37.3%	$ 183,281	36.4%

Note 11. Segments of Business

The Company is a public utility operating company engaged in the generation, distribution and sale of electric energy and the purchase, distribution and sale of natural gas to residential and commercial 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, financial resource asset, 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, temporary cash investments, 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	*1992*	*1991*	*1990*
Operating revenues			
Electric	$ 2,194,632	$ 2,196,568	$ 2,095,660
Gas	427,207	351,161	361,242
Total	$ 2,621,839	$ 2,547,729	$ 2,456,902
Operating expenses *(excludes federal income taxes)*			
Electric	$ 1,354,959	$ 1,252,993	$ 1,151,105
Gas	352,777	338,295	322,515
Total	$ 1,707,736	$ 1,591,288	$ 1,473,620
Operating income *(before federal income taxes)*			
Electric	$ 839,673	$ 943,575	$ 944,555
Gas	74,430	12,866	38,727
Total	914,103	956,441	983,282
AFC	(12,111)	(5,794)	(7,5[illegible]
Other income and deductions	(49,128)	(48,772)	(20,3[illegible]
Interest charges	512,406	523,816	508,259
Federal income taxes—operating	172,998	169,452	180,652
Federal income taxes—non operating	(12,036)	12,201	2,629
Income before cumulative effect of accounting change	301,974	305,538	319,637
Cumulative effect of accounting change (net of applicable taxes)	—	—	11,680
Net Income	$ 301,974	$ 305,538	$ 331,317
Depreciation and amortization			
Electric	$ 104,034	$ 104,172	$ 98,022
Gas	15,103	14,783	12,862
Total	$ 119,137	$ 118,955	$ 110,884
Construction and nuclear fuel expenditures*			
Electric	$ 163,609	$ 144,356	$ 151,425
Gas	109,295	93,195	81,040
Total	$ 272,904	$ 237,551	$ 232,465

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

(In thousands of dollars)

At December 31	*1992*	*1991*	*1990*
Identifiable assets			
Electric	$ 8,351,370	$ 7,986,887	$ 7,643,963
Gas	767,444	621,570	540,3[illegible]
Total	9,118,814	8,608,457	8,184,3[illegible]
Assets utilized for overall Company operations	1,129,810	934,844	658,366
Total Assets	$ 10,248,624	$ 9,543,301	$ 8,842,684

Note 12. Quarterly Financial Information
(Unaudited)

	(In thousands of dollars except earnings per common share) 1992	1991
Operating revenues		
For the quarter ended March 31	$ 697,761	$ 657,921
June 30	580,498	543,250
September 30	747,729	773,706
December 31	595,851	572,852
Operating income		
For the quarter ended March 31	$ 179,741	$ 207,830
June 30	166,954	166,830
September 30	256,800	268,041
December 31	137,610	144,288
Net income		
For the quarter ended March 31	$ 66,706	$ 86,404
June 30	59,285	50,089
September 30	141,388	144,449
December 31	34,595	24,596
Earnings for common stock		
For the quarter ended March 31	$ 50,553	$ 69,567
June 30	41,040	33,013
September 30	126,295	128,175
December 31	20,132	8,389
Earnings per common share		
For the quarter ended March 31	$ .45	$ .62
June 30	.37	.30
September 30	1.14	1.15
December 31	.18	.08

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 as of December 31, 1992 and 1991 and the related statements of income, shareowners' equity and cash flows for each of the three years in the period ended December 31, 1992. 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, 1992 and 1991, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles.

Ernst + Young

Melville, New York
February 5, 1993

Summary of Operations *(See Notes to Financial Statements)*

Tab[illegible]

	1992	1991	1990	1989	[illegible]
Total revenues (000)	$ 2,621,839	$ 2,547,729	$ 2,456,902	$ 2,347,614	$ 2,137,834
Total operating income (loss) (000)					
Before federal income taxes	$ 914,103	$ 956,441	$ 983,282	$ (93,997)	$ 701,049
After federal income taxes	$ 741,105	$ 786,989	$ 802,630	$ 620,423	$ 500,938
Income (loss) before cumulative effect of accounting changes (000)	$ 301,974	$ 305,538	$ 319,637	$ (95,803)	$ 298,490
Cumulative effect of accounting change for unbilled gas revenues (net of taxes) (000)	—	—	$ 11,680	—	—
Cumulative effect of accounting change for disallowed costs (net of taxes) (000)	—	—	—	—	$(1,345,110)
Earnings (loss) for common stock (000)	$ 238,020	$ 239,144	$ 263,156	$ (175,035)	$(1,121,128)
Average common shares outstanding (000)	111,439	111,348	111,290	111,215	111,177
Earnings (loss) per common share					
Before cumulative effect of accounting changes	$ 2.14	$ 2.15	$ 2.26	$ (1.57)	$ 2.02
Cumulative effect of accounting changes	—	—	.10	—	(12.10)
Earnings (loss) per common share	$ 2.14	$ 2.15	$ 2.36	$ (1.57)	$ (10.08)
Pro forma earnings — with accounting changes for unbilled gas revenues and disallowed project costs applied retroactively					
Earnings (loss) for common stock (000)			$ 251,476	$ (173,251)	$ 223,712
Earnings (loss) per common share			$ 2.26	$ (1.56)	$ 2.01
Common stock dividends declared per share	$ 1.72	$ 1.60	$ 1.25	$ .50	—
Common stock dividends paid per share	$ 1.71	$ 1.55	$ 1.125	$ .25	
Book value per common share at year end	$ 19.58	$ 19.13	$ 18.57	$ 17.45	$ 1[illegible]
Common shareowners at year end	86,111	90,435	82,903	85,142	93,[illegible]
Ratio of earnings to fixed charges	1.90	1.93	1.98	*	1.95
Ratio of earnings to combined fixed charges and preferred stock dividends	1.59	1.60	1.64	*	1.58
Ratio of earnings to fixed charges (excluding AFC and RMC)	1.73	1.40	1.36	*	1.60
Ratio of earnings to combined fixed charges and preferred stock dividends (excluding AFC and RMC)	1.46	1.17	1.12	*	1.30

**The Company had no earnings to cover fixed charges.*

(In thousands of dollars)

Operations and Maintenance Expense Details

Table 2

	1992	1991	1990	1989	[illegible]
Total payroll and employee benefits	$ 413,817	$ 398,000	$ 357,689	$ 329,694	$ 314,341
Less — Charged to construction and other	124,076	123,838	97,650	117,761	129,990
Payroll and employee benefits charged to operations	289,741	274,162	260,039	211,933	184,351
Fuels — electric operations	282,138	354,859	444,458	461,576	410,174
Fuels — gas operations	182,201	175,046	175,877	188,139	172,431
Purchased power costs	280,914	197,154	168,749	128,368	88,465
Fuel cost adjustments deferred	(3,469)	41,643	(2,085)	(5,631)	3,359
Total Fuel and Purchased Power	741,784	768,702	786,999	772,452	674,429
All other	208,204	248,597	215,770	215,373	173,5[illegible]
Total Operations and Maintenance Expense	$ 1,239,729	$ 1,291,461	$ 1,262,808	$ 1,199,758	$ 1,032,[illegible]
Employees at December 31	6,502	6,605	6,630	6,239	6,281

(In thousands of dollars)

Electric Operating Income

Table 3

	1992	1991	1990	1989	1988
Revenues					
Residential	$ 1,045,799	$ 1,047,490	$ 997,868	$ 915,644	$ 835,584
Commercial and industrial	1,076,302	1,070,098	1,017,387	981,740	883,267
Other system revenues	49,395	47,838	46,673	42,232	40,518
Total system revenues	2,171,496	2,165,426	2,061,928	1,939,616	1,759,369
Sales to other utilities	9,997	23,040	24,140	42,880	24,152
Other revenues	13,139	8,102	9,592	792	3,412
Total Revenues	2,194,632	2,196,568	2,095,660	1,983,288	1,786,933
Expenses					
Operations — fuel and purchased power	559,583	593,656	611,122	584,313	501,998
Operations — other	294,909	296,798	271,608	237,931	195,283
Maintenance	105,341	127,446	118,545	115,502	96,599
Depreciation and amortization	104,034	104,172	98,022	91,759	82,811
Base financial component amortization	100,971	100,971	100,971	50,485	—
Regulatory liability component amortization	(88,573)	(88,573)	(88,573)	(44,286)	—
Other regulatory amortizations	(21,984)	8,666	14,427	1,248	—
Rate moderation component	(30,444)	(228,572)	(297,214)	(131,167)	—
Regulatory liability component	—	—	—	793,592	—
Jamesport amortization	—	—	—	104,160	—
Operating taxes	331,122	338,429	322,197	312,456	262,644
Federal income tax — current	530	515	3,138	14,612	18,394
Federal income tax — deferred and other	158,908	173,259	169,274	(738,500)	166,557
Total Expenses	1,514,397	1,426,767	1,323,517	1,392,105	1,324,286
Electric Operating Income	$ 680,235	$ 769,801	$ 772,143	$ 591,183	$ 462,647

(In thousands of dollars)

Gas Operating Income

Table 4

	1992	1991	1990	1989	1988
Revenues					
Residential — space heating	$ 243,950	$ 190,976	$ 198,734	$ 209,192	$ 201,312
— other	33,035	29,383	30,854	31,692	31,803
Non-residential — space heating	90,363	70,938	68,441	72,351	68,114
— other	29,094	25,515	26,501	28,674	28,078
Total firm revenues	396,442	316,812	324,530	341,909	329,307
Interruptible revenues	19,658	21,686	30,515	19,226	18,821
Total system revenues	416,100	338,498	355,045	361,135	348,128
Other revenues	11,107	12,663	6,197	3,191	2,773
Total Revenues	427,207	351,161	361,242	364,326	350,901
Expenses					
Operations — fuel	182,201	175,046	175,877	188,139	172,431
Operations — other	77,300	78,469	68,910	59,587	53,415
Maintenance	20,395	20,046	16,746	14,286	12,599
Depreciation and amortization	15,103	14,783	12,862	11,671	10,785
Regulatory amortizations	(88)	—	—	—	—
Operating taxes	57,866	49,951	48,120	51,935	48,220
Federal income tax — current	—	—	500	—	—
Federal income tax — deferred and other	13,560	(4,322)	7,740	9,468	15,160
Total Expenses	366,337	333,973	330,755	335,086	312,610
Gas Operating Income	$ 60,870	$ 17,188	$ 30,487	$ 29,240	$ 38,291

	1992	1991	1990	1989	[illegible]
Electric Sales and Customers					Tabl[illegible]
Sales — millions of kWh					
Residential	6,788	7,022	7,022	7,063	6,979
Commercial and industrial	8,181	8,322	8,359	8,636	8,566
Other	471	469	472	470	483
System sales	15,440	15,813	15,853	16,169	16,028
Sales to other utilities	227	598	532	633	445
Total Sales	15,667	16,411	16,385	16,802	16,473
Customers — monthly average					
Residential	902,885	898,974	895,294	890,406	882,962
Commercial and industrial	101,838	101,740	101,562	100,481	98,450
Other	4,593	4,540	4,504	4,452	4,436
Customers — total monthly average	1,009,316	1,005,254	1,001,360	995,339	985,848
Customers — total at year end	1,009,028	1,005,363	1,001,441	996,488	989,097
Residential					
kWh per customer	7,518	7,812	7,844	7,932	7,905
Revenue per kWh	15.41¢	14.92¢	14.21¢	12.96¢	11.97¢
Commercial and Industrial					
kWh per customer	80,346	81,797	82,304	85,943	87,005
Revenue per kWh	13.16¢	12.86¢	12.17¢	11.37¢	10.31¢
System					
kWh per customer	15,297	15,731	15,832	16,245	16,258
Revenue per kWh	14.06¢	13.69¢	13.01¢	12.00¢	10.9[illegible]

Gas Sales and Customers					Table 6
Sales — thousands of dth					
Residential — space heating	35,089	29,687	29,810	32,024	31,276
— other	3,203	3,195	3,448	3,491	3,589
Non-residential — space heating	13,662	11,636	11,271	11,548	11,054
— other	4,338	4,171	4,352	4,539	4,580
Total firm sales	56,292	48,689	48,881	51,602	50,499
Interruptible sales	5,090	4,538	6,347	5,300	5,078
Total Sales	61,382	53,227	55,228	56,902	55,577
Customers — monthly average					
Residential — space heating	227,834	220,562	211,400	204,982	198,949
— other	169,189	171,581	176,000	179,415	181,926
Non-residential — space heating	31,666	30,453	29,072	27,733	25,979
— other	10,777	11,003	11,310	11,517	11,725
Total firm customers	439,466	433,599	427,782	423,647	418,579
Interruptible customers	531	472	410	359	325
Customers — total monthly average	439,997	434,071	428,192	424,006	418,904
Customers — total at year end	442,117	436,853	430,571	426,060	421,429
Residential					
dth per customer	96.4	83.9	85.8	92.4	91.5
Revenue per dth	$ 7.23	$ 6.70	$ 6.90	$ 6.78	$ 6.69
Non-residential					
dth per customer	424.1	381.3	386.9	409.9	41[illegible]
Revenue per dth	$ 6.64	$ 6.10	$ 6.08	$ 6.28	$ [illegible]
System					
dth per customer	139.5	122.6	128.9	134.2	132.7
Revenue per dth	$ 6.78	$ 6.36	$ 6.43	$ 6.35	$ 6.26

Electric Operations	1992	1991	1990	1989	1988
					Table 7
Energy — millions of kWh					
Net generation	10,592	13,570	13,981	15,220	15,228
Power purchased — net	6,211	3,638	2,989	2,087	1,940
Total system requirements	16,803	17,208	16,970	17,307	17,168
Company use and unaccounted for	(1,363)	(1,395)	(1,117)	(1,138)	(1,128)
System sales	15,440	15,813	15,853	16,169	16,040
Sales to other utilities	227	598	532	633	433
Total Energy Available	15,667	16,411	16,385	16,802	16,473
Peak Demand — mW					
Station coincident demand	2,975	3,085	3,260	3,178	3,347
Power purchased — net	636	819	426	510	475
System Peak Demand	3,611	3,904	3,686	3,688	3,822
System Capability — mW					
LILCO stations	4,091	4,078	4,077	4,066	3,834
Nine Mile Point 2 (LILCO's 18% share)	188	194	194	194	194
Firm purchases — net	170	244	300	400	482
Total Capability	4,449	4,516	4,571	4,660	4,510
Fuel Consumed for Electric Operations					
Oil — thousands of barrels	10,656	15,314	16,401	20,480	19,927
Gas — thousands of dth	34,475	32,924	36,477	26,490	29,126
Nuclear — thousands of mW days	124	154	108	105	87
Total — billions of Btu	102,126	129,937	139,874	154,669	153,828
Dollars per million Btu	$ 2.62	$ 2.61	$ 3.07	$ 2.86	$ 2.53
Cents per kWh of net generation	2.76¢	2.73¢	3.24¢	3.06¢	2.67¢
Heat rate — Btu per net kWh	10,558	10,484	10,564	10,704	10,545
Fuel Mix *(Percentage of system requirements)*					
Oil	37%	50%	56%	67%	68%
Gas	19	18	20	13	15
Purchased Power	38	25	20	16	13
Nuclear Fuel	6	7	4	4	4
Total	100%	100%	100%	100%	100%

Gas Operations					*Table 8*
Energy — thousands of dth					
Natural gas	64,911	55,579	55,407	60,359	58,743
Manufactured gas and change in storage	48	60	(15)	53	(18)
Total Natural and Manufactured Gas	64,959	55,639	55,392	60,412	58,725
Total system requirements	64,959	55,639	55,392	60,412	58,725
Company use and unaccounted for	(3,577)	(2,412)	(164)	(3,510)	(3,148)
Total Energy Available	61,382	53,227	55,228	56,902	55,577
Maximum Day Sendout — dth	448,726	435,050	406,177	462,610	431,940
System Capability — dth per day					
Natural gas	561,584	507,344	507,344	461,788	411,596
LNG manufactured or LP gas	120,700	128,200	128,200	145,600	145,600
Total Capability	682,284	635,544	635,544	607,388	557,196
Calendar Degree Days ([illegible]-year average 5,028)	5,066	4,378	4,139	5,169	5,162

(In thousands of dollars)

	1992	1991	1990	1989	[illegible]
Construction Expenditures*					Table [illegible]
Electric					
Production	$ 46,217	$ 32,541	$ 36,400	$ 59,880	$ 419,028
Transmission	15,535	12,452	23,418	9,022	13,379
Distribution	74,951	74,770	82,975	66,679	64,653
General *(includes nuclear fuel)*	5,049	9,880	(1,765)	3,615	17,227
Electric Total	141,752	129,643	141,028	139,196	514,287
Gas Total	104,028	89,950	78,766	49,847	37,518
Common Total	27,124	17,958	12,671	11,007	9,352
Total Construction Expenditures	$ 272,904	$ 237,551	$ 232,465	$ 200,050	$ 561,157

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

(In thousands of dollars)

Balance Sheet					Table 10
Assets					
Utility plant	$ 4,544,020	$ 4,334,736	$ 4,150,822	$ 3,939,410	$ 8,017,047
Less — Accumulated depreciation and amortization	1,382,872	1,332,003	1,262,743	1,158,253	1,071,923
Total Net Utility Plant	3,161,148	3,002,733	2,888,079	2,781,157	6,945,124
Regulatory asset	3,685,432	3,786,403	3,887,373	3,988,344	—
Nonutility property and other investments	20,730	9,788	6,381	6,050	69,271
Current assets	916,914	884,017	726,060	982,032	571,934
Deferred charges					
Rate moderation component	651,657	602,053	411,443	102,971	—
Shoreham post settlement costs	586,045	378,386	225,818	75,044	
Unamortized cost of issuing securities	380,267	227,713	132,875	150,610	52,[illegible]
Shoreham nuclear fuel	77,629	79,760	92,069	97,925	
Accumulated deferred income taxes	511,898	439,235	359,768	262,298	525,029
Other	256,904	133,213	112,818	73,607	162,290
Total Deferred Charges	2,464,400	1,860,360	1,334,791	762,455	740,008
Total Assets	$ 10,248,624	$ 9,543,301	$ 8,842,684	$ 8,520,038	$ 8,326,337
Capitalization and Liabilities					
Capitalization					
Long-term debt	$ 4,755,733	$ 5,001,016	$ 4,556,016	$ 4,560,016	$ 3,449,821
Unamortized premium and (discount) on debt	(14,731)	(14,850)	(23,125)	(28,587)	(25,011)
Preferred stock — redemption required	557,900	524,912	527,550	541,187	513,924
Preferred stock — no redemption required	154,276	154,371	154,674	155,592	221,050
Treasury stock, at cost	—	—	—	—	(58,430)
Retained earnings restricted for preferred stock dividend requirements	—	—	—	—	341,008
Common stock and premium	1,556,091	1,550,334	1,549,505	1,547,971	1,557,293
Capital stock expense	(39,304)	(40,216)	(42,676)	(42,916)	(56,151)
Retained earnings	667,988	620,373	560,405	436,690	679,579
Total Capitalization	7,637,953	7,795,940	7,282,349	7,169,953	6,623,083
Current Liabilities	1,191,787	492,895	449,830	470,885	583,017
Deferred Credits					
1989 Settlement credits	164,294	173,507	182,720	191,933	—
Class Settlement	167,066	173,564	167,569	164,040	—
Accumulated deferred income taxes	970,373	816,053	634,704	430,933	963,975
Other	110,341	84,035	117,172	81,443	144,[illegible]
Total Deferred Credits	1,412,074	1,247,159	1,102,165	868,349	1,107,[illegible]
Reserves for Claims, Damages, Pensions and Benefits	6,810	7,307	8,340	10,851	12,247
Total Capitalization and Liabilities	$ 10,248,624	$ 9,543,301	$ 8,842,684	$ 8,520,038	$ 8,326,337

	1992	1991	1990	1989	1988
apitalization Ratios*					Table 11
Long-term debt	65%	64%	62%	63%	53%
Preferred stock	9	9	10	10	15
Common equity	26	27	28	27	32
Total Capitalization	100%	100%	100%	100%	100%

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

Common and Preferred Stock Prices

Table 12

The common stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. The Preferred Stock $100 par value, Series B, E, I, J, K and CC and the Preferred Stock $25 par value, Series O, P, Z and AA of the Company are, and Series S, T and Y were traded on the New York Stock Exchange. The table below indicates the high and low prices on the New York Stock Exchange listing of composite transactions for the years 1992 and 1991.

			1992 Quarter				1991 Quarter			
			First	Second	Third	Fourth	First	Second	Third	Fourth
Common Stock		High	24⅝	24¼	25⅝	25⅞	23¼	23⅝	24½	25
		Low	22⅛	22⅜	23⅜	23⅝	19	21½	22⅛	23⅛
Preferred Stock										
Series B	5.00%	High	61	66	70	67	53½	54	56¾	58
		Low	56½	57	65	62	48	51½	53	52
Series E	4.35%	High	52¾	59½	62	60	47	46¼	49	52
		Low	49	49½	55	54	43½	44½	45	47½
Series I	5¾%	High	*	138	146½	*	136	131	136	141⅜
		Low	*	133	143⅛	*	125	131	134	139
Series J	8.12%	High	96½	96¼	100¾	101	85½	86	91	94
		Low	92	92½	94½	96	78	82¾	83	88⅞
Series K	8.30%	High	98½	98	102	101	85	88	91	97
		Low	94½	94	96¼	97½	78	83½	85	91
Series O	$2.47	High	28	28	29⅛	27½	25¾	26½	27	27⅝
		Low	26⅛	26	26	25½	24¼	24¾	25	26
Series P	$2.43	High	27⅞	28½	29⅜	28½	25¾	27½	27⅜	28
		Low	26⅜	27¼	27⅝	27⅝	24½	24⅜	25½	26⅝
Series S	9.80%	High	105¾	105	*	—	99⅝	101	102½	105
		Low	102	102½	*	—	96½	100	101	102
Series T	$3.31	High	—	—	—	—	27¾	27¼	—	—
		Low	—	—	—	—	26	26⅛	—	—
Series Y	$2.65	High	29	28⅜	—	—	27	27¼	28	28½
		Low	27⅝	27¼	—	—	25	25⅞	26⅜	26⅛
Series Z	$2.35	High	28¾	28	29	29	—	25½	26⅝	28⅜
		Low	27	26½	27	27⅛	—	25⅛	24⅞	26
Series AA	7.95%	High	—	—	26¾	27	—	—	—	—
		Low	—	—	25¼	25½	—	—	—	—
Series CC	7.66%	High	—	—	102	103	—	—	—	—
		Low	—	—	100⅝	100	—	—	—	—

referred Stock $100 par value, Series D 4.25% is traded in the over-the-counter market and no price data is available. The Preferred Stock $100 par value, Series L, M and R are held privately.

trades reported during this period.

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
11th Floor
101 Barclay Street
New York, NY 10286-1258
1-800-524-4458

Shareowners' Agent for Automatic Dividend Reinvestment Plan
The Bank of New York
Dividend Reinvestment Department
11th Floor
101 Barclay Street
New York, NY 10286-1258
1-800-524-4458

Annual Meeting
The Annual Meeting of Shareowners will be held on Tuesday, April 20, 1993 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.

Directors

am J. Catacosinos
irman of the Board and
Chief Executive Officer
Long Island Lighting Company

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

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Assistant General Counsel
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