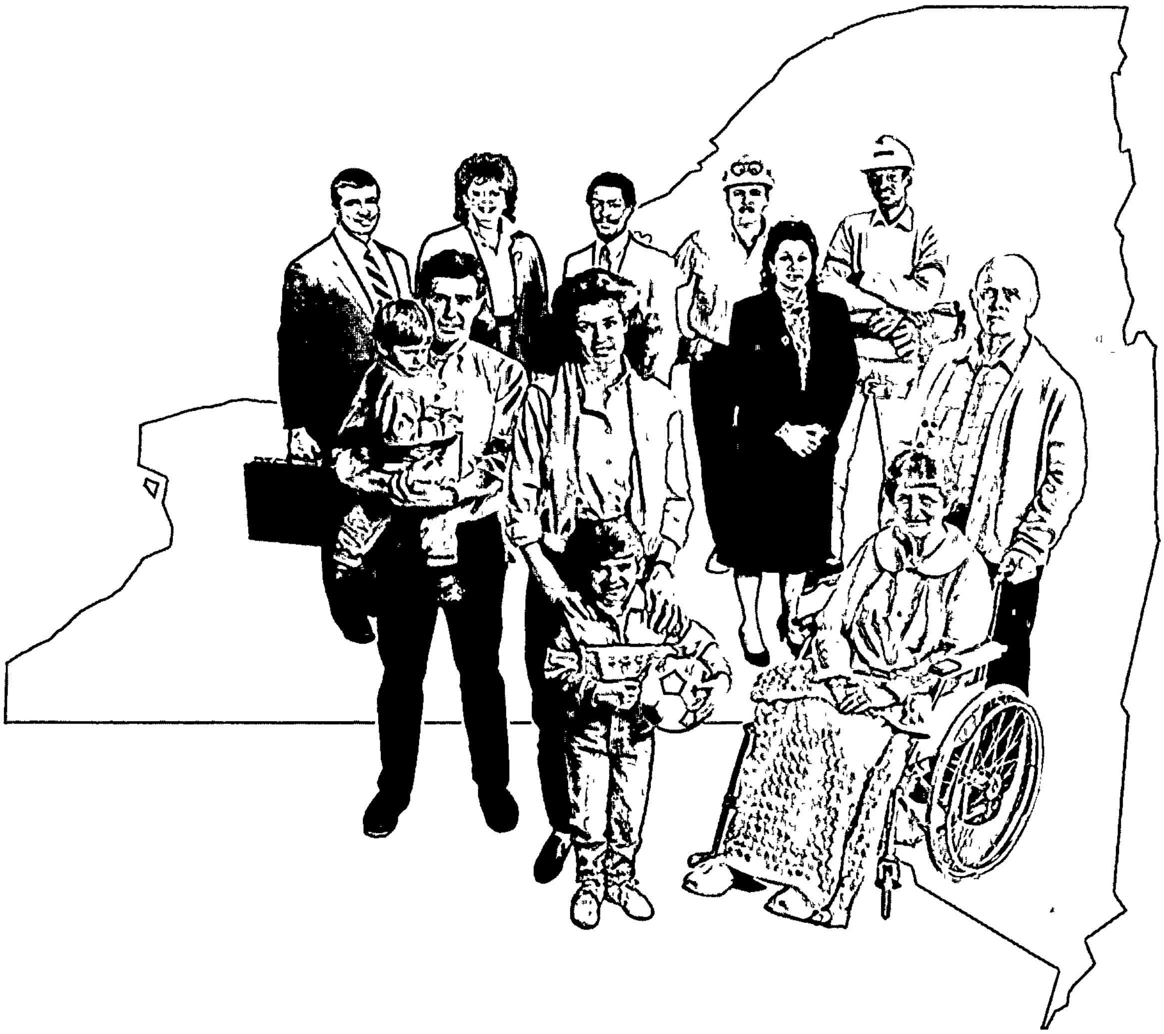
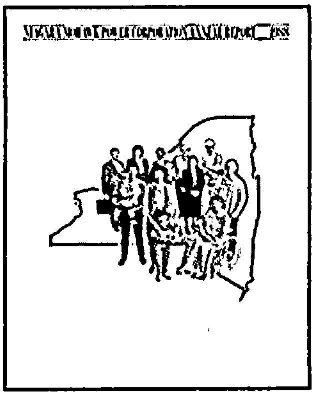
NIAGARA MOHAWK POWER CORPORATION ANNUAL REPORT 1988





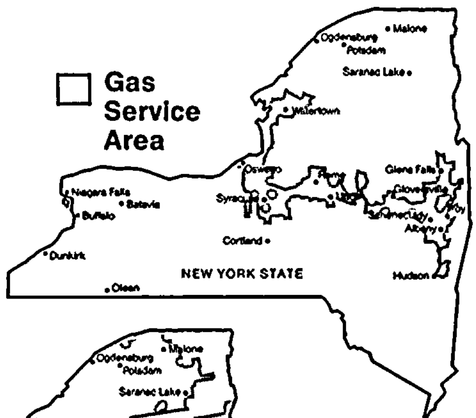
Niagara Mohawk Power Corporation Annual Report-1988

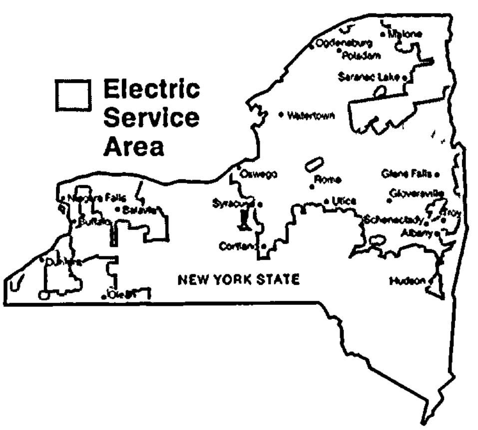
A Balance of Interests

Niagara Mohawk has an extensive constituency of electric and gas customers, shareholders, employees, pensioners and suppliers, whose well-being is interrelated. In New York, our ability to provide reliable, affordable energy has a direct impact on the upstate economy of $1 billion annually in wages and salaries, taxes, shareholder dividends and payments for New York goods and services. This $1 billion doesn't begin to approach the multiplier effect of service industry jobs that have flourished in the wake of our contributions to state and local economies.

In managing our company we strive to maintain a balance of interests among these constituencies in a complex and changing regulatory and economic environment.

In the pages that follow, you will read about our very difficult nuclear outages and our intensive efforts to remedy nuclear operations; our campaign to sensitize our employees to the changing customer environment; long-term energy procurement strategies designed to provide customers all the energy they need at competitive prices; energy conservation and varied pricing programs; economic development initiatives; customer outreach strategies; research and development activities; and other programs which we believe will work to the mutual, long-term benefit of all our constituents.





Serving our Customers in Upstate New York

Niagara Mohawk Power Corporation, an investor-owned utility, provides energy to the largest customer service area in New York State. Our electric system extends from Lake Erie to New England's borders, from Canada to Pennsylvania, and meets the needs of nearly 1.5 million residential, commercial and industrial customers. Power is supplied by hydroelectric, coal, oil, natural gas-fired and nuclear generating units as well as through purchase contracts. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

Our natural gas system serves approximately 458,000 residential and business customers with access to our 6,500-mile system of pipelines and mains in central, eastern and northern New York. In addition to the purchase, sale and distribution of gas to retail customers, a growing part of our business includes the transportation of natural gas for those customers who are large users and have arranged their own supply.

We also operate subsidiary companies in the United States and Canada. Opinac Energy Corp. operates an exploration company and a utility in Canada. HYDRA-CO Enterprises Inc. builds and operates power production facilities. NITECH Inc. markets advanced instrumentation systems to the utility industry.

This report was designed, written and produced by Niagara Mohawk People.

Financial Highlights of 1988

	1988	1987	% Change
Total operating revenues	$ 2,800,453,000	$ 2,623,430,000	6.7
Income available for *(loss to)* common stockholders	$ 159,657,000	$ (609,231,000)	—
Earnings *(loss)* per common share	$1.21	$(4.78)	—
Earnings per common share (excluding the impact of the Nine Mile Two disallowance) ..	$1.21	$1.76	(31.3)
Dividends per common share ...	$1.20	$1.64	(26.8)
Common shares outstanding *(average)*	131,853,000	127,435,000	3.5
Utility plant *(gross)*	$ 7,967,625,000	$ 7,691,069,000	3.6
Construction work in progress ...	$ 315,644,000	$ 1,789,562,000	(82.4)
Gross additions to utility plant ..	$ 353,859,000	$ 447,230,000	(20.9)
Public kilowatt-hour sales	33,263,000,000	31,530,000,000	5.5
Total kilowatt-hour sales	34,995,000,000	35,684,000,000	(1.9)
Electric customers at end of year .	1,482,000	1,459,000	1.6
Electric peak load *(kilowatts)*	6,220,000	5,780,000	7.6
Natural gas sales *(dekatherms)* ...	81,448,000	81,320,000	.2
Natural gas transported *(dekatherms)*	27,244,000	21,862,000	24.6
Gas customers at end of year	458,000	450,000	1.8
Maximum day gas sendout *(dekatherms)*	818,128	758,914	7.8

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Our Corporate Mission

Niagara Mohawk will be an innovative and responsive energy company, satisfying its customers' energy needs with a diversified line of quality and price-competitive products and services.

Electricity and gas products and services will continue to be the core of the company's business. Niagara Mohawk's driving force will be to make its electricity and gas products the preferred energy source for the largest possible number of energy users and uses. During the next three years, the company will take action to:

- Promote efficiency in the supply, demand and end-use application of energy.
- Aggressively manage its market share in key markets.
- Expand business opportunities with existing customers.
- Develop new markets for existing products and services.

In addition, Niagara Mohawk will explore and develop attractive opportunities in advanced energy-related equipment and in value-added services.

In support of this business focus, the company will:

- Maintain a high level of expertise in its core business;
- Selectively utilize resources to ensure high quality, price competitive products; and
- Substantially increase its capability to understand and respond to the customers' specific needs.□

To our Stockholders

Reliability is the essence of a utility. Our customers trust us to maintain the financial strength necessary to provide dependable, low-cost energy for their homes and businesses. Our shareholders look to us to produce a steady stream of earnings, ensuring a fair return on their investment. Our hard-working and dedicated employees want assurance that their investment in learning our business will be rewarded with satisfying careers.

In light of these facts, last year was very disappointing. The company's performance in 1988 failed to meet our expectations and causes us considerable concern for the future.

Earnings were $159.7 million or $1.21 per share, compared to $223.8 million or $1.76 last year, excluding the effect of the after-tax write-off of disallowed Nine Mile Unit Two costs of $833 million or $6.54 per share taken in 1987. With the write-off, the company reported a net loss of $609.2 million or $4.78 per share in 1987.

Many of the factors that contributed to our 1988 earnings decline extend into the present year. These include:

- the continuing impact of a reduction in the company's earnings base as a result of the 1987 write-off of disallowed costs of Nine Mile Unit Two, which began operations last spring;
- electric and gas rate agreements with the New York Public Service Commission (PSC) and other state agencies that, because of changed conditions, did not account for the costs of programs the company is now incurring; (Over the past several years, nearly every major utility in New York State has agreed to reduce or freeze rates.)
- the lengthy outage of Nine Mile Unit One, which began in December 1987 and continues, with Nuclear Regulatory Commission (NRC) involvement, into 1989;
- the extension of a planned outage at Nine Mile Two, which began in October and continues into the early months of 1989; and
- increased expenses largely related to our efforts to remedy our nuclear problems and improve nuclear operations. Both units are receiving increased monitoring by the NRC.

The Year Ahead

Return on common equity dropped to 8.7 percent in 1988, compared with 12.7 percent in 1987, excluding the write-off of disallowed Nine Mile Two costs. This deterioration is expected to deepen in 1989 as a consequence of the uncertainties surrounding the Nine Mile One outage and the increased level of expense related to nuclear operations.

The outlook for further earnings decline places considerable pressure on our dividend in 1989. The company announced a first quarter common stock dividend of 30 cents a share, which is the level we have been paying since the dividend was reduced 42 percent in the third quarter of 1987.

As we progress through the year, declaration of future dividends and levels of payment are necessarily dependent upon a variety of factors, including future earnings; cash flow; financial requirements; the duration of, and cost associated with, the outage of Nine Mile One; the adequacy and timeliness of rate relief; and the level of retained earnings. Restrictions under our charter and indenture and under federal and state law may also become a governing factor.

Early in 1989, the company agreed with the Public Service Commission that we would suspend collection from ratepayers of $225,000 a day in replacement power costs attributable to the outage.

The temporary resolution of the replacement power cost issue allows us to focus our efforts on completing the work necessary to return Nine Mile One to service. New York's attorney general, among others, had pressed hard for the PSC to begin hearings at the earliest possible time.

The suspension began in January and will continue until June 30, 1989, or the restart of the unit, whichever happens first. The possibility of the PSC mandating the same level of relief or undertaking even more stringent steps was very real, had we not entered into the agreement.

While the agreement with the PSC intentionally does not assign responsibility for the outage, the suspension of replacement power costs will reduce earnings by about 3 cents per share a month for the duration of the agreement. Our ability to recover this money in rates and our ability to avoid refunding about $76 million of purchased-power costs collected from customers in 1988 is subject to a PSC decision—expected after restart of the unit— on the causes of the outage. Meanwhile, we have been spending—and will continue to spend—substantial amounts for operation and maintenance work related to restart activities.

A Plan of Action

In December, we provided the Nuclear Regulatory Commission with a comprehensive plan for restarting Nine Mile One. We are striving to return the plant to service as soon as possible, although our current assessment indicates restart is unlikely to occur before mid-1989. Ultimately, we must gain the approval of the NRC before we can restart the unit.

To strengthen leadership and provide new perspective, we sought retired Rear Adm. Lawrence Burkhardt, a 32-year U.S. Navy nuclear veteran, to join the company as executive vice president of nuclear operations and as a member of our board of directors.

Burkhardt, whose career covered a range of highly responsible nuclear and overall fleet and administrative posts, served as assistant deputy chief of Naval operations with responsibility for 900,000 military and civilian personnel upon his retirement in 1986. Before joining Niagara Mohawk, he was a consultant to the nuclear power industry.

Although he has only been with the company since mid-November, in our view his presence already has begun to make a positive difference in employee performance. While we can expect a very challenging time ahead, the most recent regulatory inspections at our nuclear facilities have been more favorable.

Preserving Reliability

Nevertheless, there is no question that 1989 will be a difficult year. Our areas of exposure are clear, and we are taking steps to mitigate the potential impact.

Specifically, we have asked supervisors throughout our company to reassess their operating plans in 1989 for additional cost-saving measures. While we have no intention of cutting costs beyond our ability to provide reliable service, we will be taking aggressive steps to effect reductions.

Niagara Mohawk operates an extensive infrastructure of generating, transmission and distribution facilities that are subject to the ravages of time and weather and which require a continuing program of preventive maintenance. To reduce vigilance would be a disservice to shareholders and customers alike.

We also intend to pursue the possibilities of relief to cover costs associated with our nuclear program. Nine Mile One has offered an excellent value to our customers, providing more than $800 million in fuel savings during its 19 years of operations.

A Balance of Interests

Niagara Mohawk's dilemma is that our very source of strength—our uniquely diverse generating mix and our extensive distribution system—also presents a significant challenge in the current regulatory environment. Our size and diversity help to keep our costs low. They guard against the possibility that any single event will substantially increase prices. But the diversity and associated complexity of Niagara Mohawk's business heightens the likelihood that future conditions could vary from expense forecasts so closely scrutinized in the ratemaking process and to which we are so strictly held.

We are concerned that a balance of interests is not achieved if the regulatory process tends only to identify and penalize weaknesses, while strengths brought about through shareholder investment go largely unrecognized and unrewarded.

We believe it is not equitable for our shareholders to suffer a significantly reduced return on investment while our customers have received and will continue to receive the benefits of our shareholders' investment—low-cost nuclear power. There should be a balance of interests.

The key to 1989 will be our ability to meet our Nine Mile One restart schedule and win NRC approval to bring this unit back to productive service. We are concentrating significant resources on this effort specifically and on nuclear operations in general.

Our Inherent Strengths

Longer term, there are forces at work to help us bring about a gradual improvement in financial returns for our company. Our electric prices are relatively low compared with other regional suppliers. We believe this is an important factor in the renewed economic vitality we are experiencing in our service territory—a revitalization that contributed the bulk of a nearly 6 percent increase in electric usage in 1988.

Gas sales for the year also increased by more than 5 percent. To reduce costs and increase natural gas supply throughout our system, we announced plans in 1989 to participate in the development of a pipeline link to Canadian gas sources.

Our subsidiaries, Opinac Energy Corp. and HYDRA-CO Enterprises Inc., while small parts of our business, continue to register growth.

Without detracting from the gravity or seriousness of these times, we also believe we should never lose sight of our strengths. We are encouraged that the strength and importance to society of our core energy business, the growing vitality of our service territory and the validity of our strategic plan will provide the basis for us to move through this challenging period.

During 1988, we lost two members of our board of directors. We will miss the contributions of Lauman Martin, who served our company since the days of its incorporation as an officer and a director, and Lewis A. Swyer, who lent his entrepreneurial know-how and community perspective to many of our decisions.

We have always been fortunate in the talent and dedication of the people we've attracted to our business and in the loyalty shown by our customers and shareholders.□

William J. Donlon
Chairman of the Board and Chief Executive Officer

John M. Endries
President

March 8, 1989

A Balance of Interests

Redefining our concept of customer service has been a major strategic initiative for Niagara Mohawk in 1988—and will continue to be a critical planning factor in years to come.

We are facing increasing competition in all areas of our business. Programs that sharpen our customer and community focus serve the mutual interests of all our constituencies—shareholders, customers and employees alike—because they help to ensure that we will maintain leadership in our markets.

"Energy Provider"

Our process for addressing this balance of interests has thrust us into new territory in 1988 as we developed programs to:

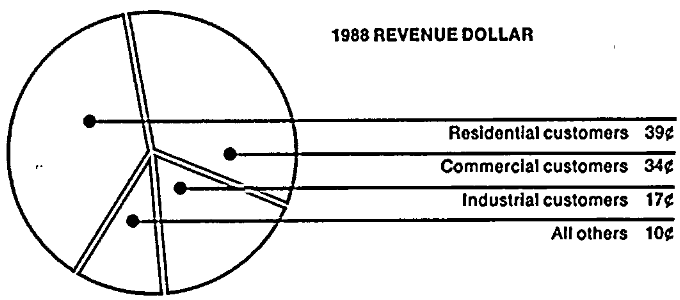
- Train 5,500 employees to be more responsive in their customer contacts.
- Forge an innovative public-private partnership aimed at encouraging business development in our service territory.
- Explore new ways to meet long-term energy needs through energy conservation, demand-side management and competitive bids by third-party suppliers.
- Provide customers with a greater degree of control over energy use and price through programs that enable them to:
  - participate in real-time energy pricing and other forms of time-of-use rates;
  - make more efficient use of energy through conservation and demand-side management methodology;
- Provide low-cost natural gas to a greater number of customers through aggressive marketing programs and by exploring new avenues of gas availability.
- Enrich our portfolio of consumer outreach programs that emphasize one-on-one assistance.
- Get the best of energy through targeted research and development.

Electric Use Indicates New Economic Vitality

Over the past decade, our base of retail customers has grown steadily at a rate of about 1 percent a year, representing an average annual increase of approximately 12,000 new electric customers and 3,000 new gas customers.

Last year was no exception in terms of base growth, but retail electric sales volume registered the sharpest increase in more than a decade—up 5.5 percent for the year, reflecting across the board gains of 7.5 percent in industrial, 4.3 percent in commercial and 4.6 percent in residential kilowatt hours.

Unusually hot summer weather was partially responsible, but we believe increased economic vitality in our service territory is the underlying cause of our retail electric sales growth in 1988. Total electric sales declined slightly reflecting the marked downturn in sales to other utilities.



Direct sale of gas, which has trended down sharply since deregulation, leveled off in 1988, led by growing demand in the residential sector of our business. The changes in federal regulation that reduced sales volume among our industrial customers have created a new business for us in gas transportation. In 1988, we registered a 25% volume increase against 1987 in transportation of customer-owned gas.

New Data Brings Us Closer to Customers
Two separate but concurrent programs in 1989 are aimed at developing more information about our customer base.

As part of our "Think Like a Customer" initiative, we will be expanding customer surveys in 1989 to derive a better measure of customer perceptions of our service. We have also assembled teams of employees in each of our operating regions to analyze customer service procedures and make recommendations to improve service.

"Energy Expert"

At the same time, our Research & Development Department will be undertaking a two-year study to profile the kinds of businesses most likely to succeed in our service territory. This will be the second phase of R&D's Industrial Technology Assessment Program which built a base of information on industry in our service territory through surveys or visits with hundreds of local businesses.□

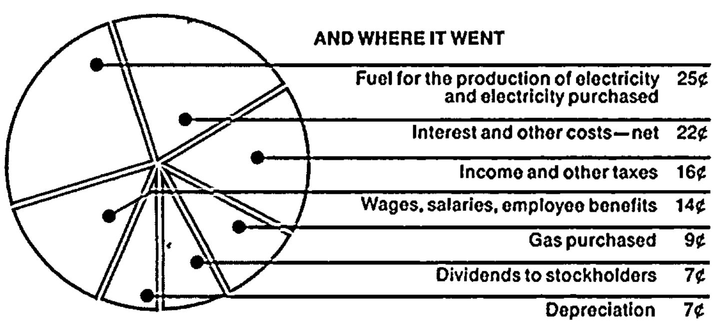
Thinking Like A Customer
"If we make mistakes with our customers," says John LaFalce, a Niagara Mohawk gas mechanic in Schenectady, "it's usually because we haven't done enough. We haven't listened well enough; we haven't provided enough information or haven't tried to see things from the customer's point of view."

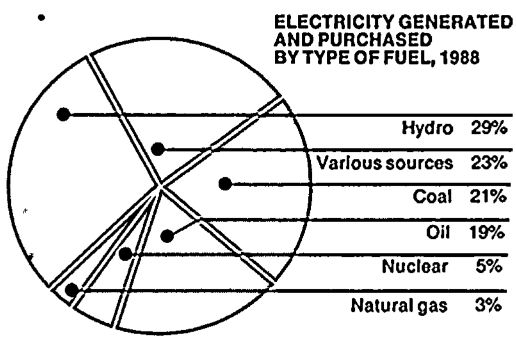
This is part of the message LaFalce is taking to co-workers in training sessions this spring. He is one of 55 Niagara Mohawk people chosen for special schooling as a facilitator, or trainer, in a companywide program to increase employee responsiveness to customer needs. Approximately 5,500 employees will participate in this training in 1989.

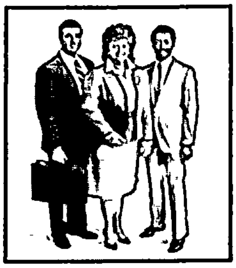
"It's not enough to say, 'I'm here to hook up your gas,' " LaFalce says. "You have to help the customer understand exactly what will take place, how much time is required and what we intend to do to restore any property disruption."

The 19-year Niagara Mohawk veteran says the training, which includes advice on dealing with irate customers and difficult situations, has application away from the job as well.

"I have more confidence," he says. "I understand how good communications can work in your favor to turn around a bad situation and make a good one that much better."□







Emphasis on Partnership

Early this year, Niagara Mohawk and New York State formed an Economic Development Partnership to create jobs in our service territory. The alliance, which has its roots in our 1988 negotiated rate agreement, will earmark $4 million over a two-year span for the attraction or expansion of very specific types of businesses.

It also underscores the emphasis we are placing on formal and informal partnerships as we explore the opportunities and responsibilities inherent in our relationships with the individuals, businesses and communities we serve.

The strength of our core utility business depends on the vitality of our customer base. At every turn, we are confirming that what works to our customers' best interests also works to ours.

The Niagara Mohawk-New York State Economic Development Partnership is one illustration of our commitment to develop mutually beneficial solutions to the long- and short-term energy needs of our customers and our communities. Other examples of this commitment include expansion of economic development rates; extension of real-time energy pricing and conservation programs; introduction of a competitive bidding program to procure new electric resources and our efforts to obtain access to Canadian gas.

"Economic vitality"

NM Discount Rates Spur Economic Development
Niagara Mohawk offers discounted energy prices to attract new business to our service territory and to help existing business renew or expand operations. We also work with companies to implement technological advances and other cost-saving systems and techniques.

Since 1984, more than 146 businesses have availed themselves of one or more of our economic development incentive rates contributing to the creation or retention of approximately 11,050 jobs.

Managing Electric Demand Provides Benefits for All
Customer electric use created new demand peaks on three occasions during the year, setting a year-end record peak on Dec. 12 of 6,220 megawatts—a level we did not expect until the early 1990's.

This growth, led by industrial demand which increased 7.5 percent during the year, demonstrates the vitality of business in our service territory.

But it also presents a challenge. Ensuring the best service at the lowest possible price means we must maintain ample and efficient supplies of electricity, while skillfully keeping expenses— and the need to acquire or build new capacity—at a minimum.

During 1989, Niagara Mohawk will be engaged in the development and implementation of a range of energy pricing and conservation programs to make the customer and the company winners.

For instance, technological advances and innovative pricing are giving some of the company's largest industrial customers a look at tomorrow's electricity prices today. These customers can reshuffle manufacturing steps to realize substantial savings, because each day they are given prices based on the costs of production at the time.

In 1989, we will begin extending time-of-use pricing to our largest residential customers. Time-of-use rates will not only give homeowners the ability to control their electric costs, it will also help us shift electric demand away from peak hours of the day.

And, in the months ahead, Niagara Mohawk will be considering a number of programs that use simple energy conservation tactics to reduce peak load.

These demand-side efforts will tend to shift electric usage to off-peak hours and may reduce revenues over the short term. This is a factor under consideration in the regulatory process. Longer term, strategic load shifting can help defer the need for new generating capacity.

Competitive Bidding Promises Alternatives to Construction

The substantial financial risk in building large electric plants today makes few utilities eager to embark on major new construction projects.

In the near term, additional electric capacity probably will come from relatively small, widely scattered independent power plants and from conservation and load-shifting programs.

"New Programs"

Niagara Mohawk's territory, rich in both natural resources and industrial customers, has drawn a flood of proposals from independent developers. The challenge now is adding that new capacity in a sensible and cost-effective manner.

The most promising alternative is a public bidding program. Competitive bidding could allow Niagara Mohawk to add capacity as customer demand grows—and to increase the number of productive partnerships it enjoys with many independent power producers.

Bids could include proposals for new generators, energy conservation or other steps that would postpone the need for new plants.

The company submitted a bidding proposal to the New York State Public Service Commission in October. In 1989, we expect to conduct our first auction for 350 megawatts of capacity, which would become available in 1994.

NM Plans Strategic Link to Canadian Gas

Natural gas continues to be the heating fuel of preference for new home builders in our service territory. It's also the number one choice of homeowners contemplating furnace replacements.

Co-generation is another market we are actively exploring. Gas transportation contracts with industrial users offer opportunities for enhanced revenues along with the potential for balancing the sharp winter demand peaks typical of residential gas use patterns.

As we move to capitalize on this demand through an aggressive program of contacts with industrial customers and franchise expansion, we are also exploring avenues of new supply—especially Canadian natural gas.

We signed an agreement with TransCanada PipeLine Ltd. early this year to pursue plans to build a 25-mile line across the St. Lawrence River. The transaction, which also includes a contract for natural gas supply, doesn't rule out several other options at our disposal—including the proposed Iroquois pipeline through Central New York. But, at this juncture, it appears to be the most timely, cost-effective choice.

If we are successful in obtaining the necessary regulatory approvals and rights of way, we could have the new pipeline in service as early as November 1990.

Access to Canadian gas is important for several reasons: 1) it strengthens our ability to supply our rapidly growing market; 2) its lower price reduces our overall cost to customers; and 3) it provides a strategic link to additional suppliers.

In 1988, we added 7,500 new customers and 194 miles of new gas main. We also won the right to serve three new franchises last year and are pursuing the benefits of offering service to the many additional areas that have become attractive in recent years due to urban expansion.

Prospects continue strong for natural gas service, which accounted for approximately 16 percent of our total corporate revenue in 1988. Deregulation and attractive prices are creating new avenues of supply and demand.■

Emphasis on Partnerships

Energy-cost reduction wasn't just a goal, it was a life-or-death proposition for Crucible Specialty Metals four years ago. Francis Petro, who became president of the Syracuse-based division of Crucible Materials Corp., shortly after a 1985 management buyout, said the specialty steel producer was literally smelting its profits away.

"To compete in the global marketplace for steel, we need 100 percent electrical reliability at the lowest possible cost," Petro recalls telling Niagara Mohawk. "Is that unreasonable?"

Through a program that included industrial gas conversion, time-of-use rates and economic development incentive rates, Niagara Mohawk helped Crucible slash its energy bill. Petro says this was a major component in a larger program the 1,450-employee company undertook to make its steel more price-competitive.

"The average price of all our products is more competitive in the world market than it was in 1979," Petro says. "And we're selling in at least 12 countries and growing, where we didn't have a foothold two years ago."□

Cultivating the Highest Standards

Commercial operation of Nine Mile Two in 1988 was the final installment in a major building program. During the past 25 years, Niagara Mohawk has added nearly 3,500 megawatts of electric power to the New York Power Pool—and increased our system capacity almost 88 percent—with the construction of Nine Mile Point Units One and Two; Oswego Steam Units Five and Six; and the Granby Hydroelectric Station.

The legacy of Niagara Mohawk's construction era is a low-cost mix of nuclear, hydroelectric, coal, oil and natural gas generating capacity. Combined with purchased power arrangements, we have confidence that we can meet our customers' needs into the next century, without embarking on another cycle of major plant construction.

As we make the transition from a construction era to an operations era, our strategy is to:

- maintain the low-cost advantage of our existing plants through judicious refurbishment and high operating standards;
- balance growing demand, where possible, with demand-side management and conservation methodology;
- employ third-party producers, through competitive bidding, when new capacity is required;
- increase customer access to natural gas, a plentiful, economical energy source.

"Record Production"

Fossil Plants Take Advantage Of 1988 Oil Price Decline

Niagara Mohawk's fossil (coal, oil and natural gas-fired) plants set new production records in 1988, demonstrating the versatility and flexibility of this generating source.

We maximized the use of oil-burning units in Albany and Oswego as the price of fuel oil declined as much as 25 percent below prior-year levels. This oil price decline, while partly due to market forces, was also a result of our success in renegotiating a long-term oil supply contract for our Oswego Station. The new contract terms resulted in a savings of approximately $15 million in fuel oil costs in 1988. Late in 1988, we successfully pursued yet another, though much more modest, long-term oil contract improvement which will result in some additional savings in 1989.

With hydroelectric production down 6.8 percent due to unusually dry weather and with Nine Mile One off line, fossil generation was a low-cost alternative to expensive purchased power.

Our strategy on fossil generation is to take full advantage of the economies of our existing facilities. Encouraged by the continuing low price of oil and off-system sales opportunities, we plan to add about 170 megawatts of fossil generation capacity in 1989 by revitalizing an older oil-fired unit and two gas turbines. Much of this additional power is targeted for sale to the wholesale market.

Moreover, our continuing life-extension studies indicate that our fossil units, built for 45 years of productive service, are capable of at least 60 years' operation with modest repairs. While we plan to weigh the cost of refurbishment against demand-side management and non-utility production alternatives, we are encouraged by the integrity of our existing plants.

NM's People Accept Nuclear Challenge

Our nuclear plants are a significant asset, representing about 19 percent of our generating capability. Nine Mile One, a nuclear power industry pioneer, will celebrate the 20th anniversary of its commercial operation in 1989. Nine Mile Two, a new and more complex facility, is just beginning what promises to be a long and productive life.

At year end, both units were listed on the Nuclear Regulatory Commission's roster of plants requiring closer monitoring. Nine Mile One, shut down since

Dec. 19, 1987, was placed on the list last June. Nine Mile Two was added to the list in December, reflecting the NRC's concern following the plant's uneven first year of operation.

Nine Mile Two currently is under no restrictions for operations but our ability to restart Nine Mile One is subject to approval of NRC Region 1 staff, based on our successful completion of a restart action plan.

The problems underscored by the NRC are more managerial than technical and reveal the regulatory body's concern for the preparedness of people entrusted with day-to-day nuclear operations. Our challenge is to complete the work planned in the Unit One restart program filed with the NRC this past December, and achieve progress on our nuclear improvement program. This will revitalize the morale and spirit of our nuclear workers, who have been laboring long and hard to bring the sophisticated, new Nine Mile Two to maximum efficiency and to prepare the older Nine Mile One for its remaining 15-year sprint—or longer if its operating license is extended.

"Fuel Savings"

Our people have ensured that Nine Mile One's productivity, during its two decades of service, has consistently ranked with the best reactors of its kind and has provided over $800 million in fuel savings—with approximately half that total accumulated between 1983 and 1987. In 1987, Nine Mile One set the productivity record for U.S. boiling water reactors.

We are keenly aware of the costs incurred each day this facility is out of service. We are committed to meeting our schedule on Nine Mile One and having both nuclear plants in productive operation in 1989.

NM Pursues New Strategies To Extend Hydro Legacy
Our company not only derives its name from two rivers but about one-third of its power comes from Upstate New York's abundant waterways. We generate low-cost hydroelectric power at 77 sites in our system and buy additional supplies under a long-term contract with the New York Power Authority. In 1988, we agreed in principle with NYPA to extend this contract until 2007.

While the average age of our hydro stations is approximately 60 years, they remain capable of highly efficient operations. For example, in 1988 they produced 94 percent of the energy theoretically possible for them to provide. Over time, we've managed to take advantage of low hydroelectric power costs through programs that extend the lives and productivity of our plants.

This process has become increasingly complex, however, as we endeavor to work in good faith to satisfy a growing list of waterway interest groups, ranging from recreationalists, environmentalists, and fishing enthusiasts to civic and industry groups, private businesses and non-utility power producers.

Our strategy recently has been to redevelop plants through joint ventures with independent power producers, using designs that address the concerns of all interests. The Glen Park and Union Falls stations, opened in 1987 and 1988, respectively, and the Middle Falls station, currently under construction, are good examples.

Further plans for redevelopment are dependent on our progress in retaining federal operating licenses. In 1993, federal relicensing decisions are due on nearly half of our hydroelectric plants.■

Building a Winning Team
Larry Burkhardt, Niagara Mohawk's new executive vice president of nuclear operations, believes he was recruited "to build a winning team" and often reminds his colleagues that they are "running this race to win."

"Second best just gets mud in your face," says Burkhardt, who uses sports analogies to remove some of the abstraction from the term "excellence" and to help drive home the importance of discipline and teamwork.

A 32-year Navy nuclear veteran who, on his 1986 retirement as a rear admiral, held administrative and policy responsibility for 900,000 military and civilian personnel, Burkhardt is encouraged by the company's goal of becoming "the best" nuclear utility.

"We have technical competence, loyalty and dedication," Burkhardt says of the nuclear workforce. "Now, we just have to improve our effectiveness and get into the habit of winning—beginning with a few small successes and building on them until we've come to expect nothing less."■

Exerting Special Care

As energy demand climbs in our service territory and unemployment declines, it's tempting to paint a picture of unremitting prosperity. But our people dealing day-to-day with customers tell a different story.

Meter readers, customer representatives, service personnel and other Niagara Mohawk people who work closely with the public, present us with a portrait of a growing number of customers who have difficulty managing their daily affairs.

As at other utilities, we have been actively developing programs to provide assistance. These include energy conservation activities, health and safety programs and our efforts to improve the readability and content of our bills. But increasingly, we are focusing our efforts on those who require special care.

"Humanitarian View"

Our interests are bottom-line oriented as well as humanitarian. We know there's help available for the elderly, the disabled, the poor and the otherwise disadvantaged, who make up the largest proportion of our uncollectibles. But often, they need assistance in getting the help they need.

Four programs, introduced in 1988, are especially noteworthy:

Club SENIORITY—Customers age 60 years and older frequently need special services. Through an aggressive advertising and customer outreach program, we identified 119,000 senior citizens, or approximately one-third of the estimated total in our territory by asking them to enroll in Club SENIORITY. The drive continues in 1989.

Membership entitles customers to a special newsletter and assures them of special attention from our consumer services personnel.

Energy Packaging—Energy-related programs devised for the low-income elderly are often undersubscribed because this interest group can least afford to participate. In 1988, Niagara Mohawk provided money that enables five New York county agencies involved with aging to hire individuals called "Energy Packagers" who will help low-income elderly households take advantage of a wide range of available services, including home weatherization and repair, furnace-replacement and bill payment programs.

To date, special assistance is being provided to 180 homes or individuals through this program, which is conducted through the State Office for the Aging and extends through 1989.

Consumer Advocates—In 1988, Niagara Mohawk completed its first full year of operating a team of specially trained employees, with backgrounds in social work or social services, to act as ombudsmen for customers in five regions. Consumer advocates intervene in difficult and emergency situations, using company programs and help from human-service agencies to promptly solve customer problems.

Gatekeeper—Jointly sponsored by Niagara Mohawk and the State Office for the Aging, this program trains those employees, who frequently come in contact with customers, to be sensitive to conditions that indicate economic, emotional or health problems in homes—particularly those of senior citizens. Through referrals provided by Niagara Mohawk people, human-service agencies receive the information they need to take appropriate action.

Subsidiary Growth Represents Commitment to Diversification

Niagara Mohawk's subsidiaries, Opinac Energy Corp. and HYDRA-CO Enterprises, Inc., continued their record of growth in 1988.

"Diversification"

At year end, the Canadian-based Opinac Exploration, Ltd. had estimated proven reserves of 173 billion cubic feet of natural gas and 1.8 million barrels of crude oil for a combined value of $82 million (U.S.). This compares with 138 billion cubic feet of natural gas and 1.4 million barrels of crude-oil proven reserves in 1987 for a combined value of $65 million (U.S.). Opinac Energy also operates Canadian Niagara Power Co., Ltd., which generates electricity at Niagara Falls, Ontario.

HYDRA-CO Enterprises Inc., Niagara Mohawk's presence in the field of co-generation and independent power production, brought an additional 36 megawatts of power on line in 1988 with the completion of a wind power and a hydroelectric project.

By December, the small power producer had the ability to generate 173 megawatts of electricity, with 203 megawatts of generating capacity under construction and 113 megawatts in development.

Niagara Mohawk also maintains an investment in NITECH Inc., which was developed to produce and market the Power-Donut (tm) Sensor Line Monitoring System, originally a Niagara Mohawk research project.

Niagara Mohawk's diversification strategy is to own and operate energy-related businesses.

NM Maintains Active Investor Program

Our Investor Relations and Shareholder Services departments conduct a program of regular communications with shareholders, which includes annual and quarterly reports and a quarterly "In The Know" newsletter for shareholders who have requested additional information.

Company representatives meet regularly with the security analysts and portfolio managers who advise a broad range of retail and institutional clients. On Dec. 31, institutions held about 26 percent of the company's common shares outstanding.

Dividend Reinvestment Plan

At year-end 1988, some 62,945 dividend-reinvestment plan participants held approximately 19.5 million shares of the company's stock, or 14.5 percent of the company's outstanding common shares. This participation resulted in the reinvestment of more than $23.1 million in dividends in Niagara Mohawk stock during the year.

A prospectus describing the plan and an authorization form to join may be obtained by writing Niagara Mohawk's Dividend Reinvestment Plan, P.O. Box 7058, Syracuse, New York 13261.

Delivering Extra Help

Leo Reiter says his job hasn't skipped a beat since he left the Erie County Department of Social Services to join Niagara Mohawk recently as a consumer advocate. Leo's job is to make sure that people entitled to special help in paying their energy bills, get it.

"I know all the social service agencies. I know the rules. We have good working relations," Reiter says. Further, he believes that agencies such as the County Departments of Social Services, the Offices for the Aging, Red Cross and Catholic Charities, to name a few, appreciate having a local company contact who understands their workings.

His clients are frequently elderly or disabled people, or families with deep financial problems. They are either unaware of, or physically or mentally unable to secure, available energy related support.

Referrals typically come through Niagara Mohawk's Credit Department, but meter readers and service representatives also make a significant contribution. "No business enters people's homes with the regularity we do. We have a unique opportunity to solve some of our own problems by helping others."

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

A number of significant events have occurred during the past several years which have had an impact on the Company's financial condition and results of operations. Some of the more notable events include:

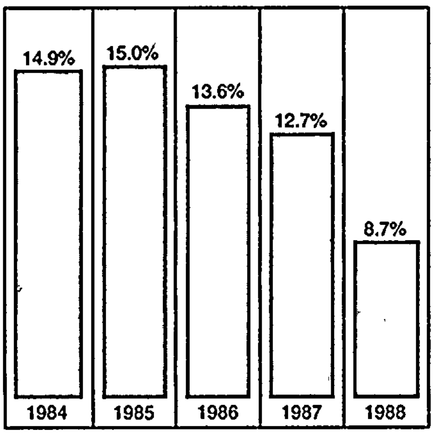
- commercial operation of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2), approval of the Unit 2 cost settlement agreement and associated write-off of disallowed costs in 1987 (see Note 10 of Notes to Consolidated Financial Statements),
- a 42% reduction in the common stock dividend to the current level,
- negotiated two-year electric (the Stipulation Agreement) and gas rate moratoriums and the resolution of other outstanding issues (as defined below) with the Public Service Commission (PSC), discussed in more detail below,
- continued emphasis on improving customer service and identifying market opportunities, enhancing system reliability and revitalizing the nuclear program with a resultant increase in the level of operating expenditures, and
- the continuing outage of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) which began in December 1987, and the implementation of an interim relief agreement with respect to replacement power costs associated with the Unit 1 outage, beginning with the fuel cost month of January 1989, in connection with the proceeding established by the PSC to investigate the Unit 1 outage (see Note 10 of Notes to Consolidated Financial Statements).

The effects of these and other events will continue to influence the Company's financial results in 1989 and possibly beyond.

RESULTS OF OPERATIONS

For 1988, earnings per share decreased 31% to $1.21 per share compared to 1987's $1.76 per share earned prior to reflecting the loss of $833 million ($6.54 per share) relating to the write-off of disallowed Unit 2 costs in 1987 (see Note 10 of Notes to Consolidated Financial Statements). This decrease is attributable to a number of significant factors, including a full year's impact of the reduction in the Company's earnings base resulting from the Unit 2 write-off as initially reflected in the Company's March 1987 rate order, certain provisions of the electric and gas stipulation agreements, which because of changed conditions did not account for the costs of programs that the Company is now incurring, the Unit 1 extended outage (see Note 10 of Notes to Consolidated Financial Statements) and a further write-down of the Company's investment in N M Uranium, Inc. (see Note 3 of Notes to Consolidated Financial Statements) which were offset in part by an increase in electric sales to the public. Non-cash earnings, consisting primarily of allowance for funds used during construction and unbilled revenue, represented approximately 10% of the balance of income available for common stockholders in 1988 and are expected to increase to nearly 40% in 1989.

EARNED RATE OF RETURN ON COMMON EQUITY



As a reflection of these events, the Company achieved an 8.7% return on common equity in 1988 as compared with 12.7% (excluding the Unit 2 write-off) in 1987 and 13.6% in 1986. Although no authorized return on equity was established in the Stipulation Agreement, the Company had anticipated a return on equity of approximately 10.0% in consideration of the provisions of the Stipulation Agreement and an estimate of the incremental costs of the Unit 1 outage. The authorized return on equity at December 31, 1987 and 1986 was 13.0% and 13.5%, respectively. The return on equity for 1989, while based upon certain assumptions that cannot be predicted with accuracy, is expected to be less than the actual earned return on equity for 1988 as a consequence of, among other things, the continuing uncertainties surrounding the Unit 1 outage and the associated PSC prudency investigation (see Unit 1 outage discussion below) as well as a continuation of or increase in the level of operating expenses experienced by the Company.

In May 1988, the Company, PSC Staff and several intervening parties (including the New York State Consumer Protection Board, the New York Department of Law, the New York Department of Economic Development and others) entered into a comprehensive Joint Stipulation and Agreement (the Stipulation Agreement) concerning the Company's then pending electric rate filing and several other pending matters. The Stipulation Agreement was approved by the PSC in an order issued August 30, 1988. The major provisions of the Stipulation Agreement were as follows:

- The Company agreed to no increase in base rates for electric service through June 30, 1990.
- The Company agreed to refund to ratepayers $14 million over the twelve month period ending June 30, 1989.
- The PSC proceeding ordered in 1987 to inquire into the cost of past fuel procurement practices was dismissed, based upon the provisions of the Stipulation Agreement, in its entirety.
- The PSC, in connection with its investigation into the fossil fuel procurement practices of the Company, will continue its examination of the existing fuel adjustment clause (which was subsequently expanded into a statewide generic proceeding). However, modification to the existing fuel adjustment clause, if any, shall not be made effective for the Company prior to July 1, 1990.
- The Company will be allowed to keep amounts earned up to 13.8% and 14.0% return on equity for the twelve month periods ending June 30, 1989 and June 30, 1990, respectively, subject to certain assumptions and rate-making conventions used in the Stipulation Agreement, with an equal

sharing with consumers of any earnings in excess of those amounts; however, the Company expects to earn substantially less than the return on equity caps established.

- The Company will be allowed to reflect in income approximately $50 million in unbilled electric revenues, representing non-cash earnings, to offset otherwise required increases in costs over the two year period.
- The Company was permitted to recover approximately $41 million of its $47 million investment in the Lake Erie Generating Station Project. The remaining $6 million of the Company's investment was charged against Other Income Deductions.
- For the Company's ratemaking purposes, April 5, 1988 will be recognized as the commercial operation date for Unit 2. The Company deferred all costs of operating Unit 2 from April 5, 1988 to June 30, 1988 including carrying charges. Such deferred costs shall be amortized and recovered over the life of Unit 2.
- The Company will spend $4 million on economic development programs to be developed in conjunction with the New York Department of Economic Development.

The effect of the recognition of the $14 million refund, the write-off of a portion of the Lake Erie Generating Station Project costs, the accrual of unbilled electric revenues and the accrual of economic development program expenditures on 1988 results of operations was to reduce earnings per share by $.15.

As discussed further in Note 10 of Notes to Consolidated Financial Statements, Unit 1 was taken out of service in December 1987, and currently remains out of service. On September 8, 1988, the PSC instituted a proceeding to investigate the prudence of the Unit 1 outage. Through the function of the fuel adjustment clause sharing mechanism, the Company has absorbed through December 31, 1988 approximately $17.2 million of replacement power costs necessitated by the Unit 1 outage and has collected from ratepayers approximately $75.9 million. The Company has also absorbed approximately $26.7 million of incremental Unit 1 operating and maintenance costs in excess of amounts provided for in the ratesetting process.

The Company entered into an interim relief agreement with the PSC Staff and other intervenors, which was approved by the PSC in January 1989, to suspend collection from ratepayers of $225,000 per day through the fuel adjustment clause, commencing with the fuel cost month of January 1989 until the earlier of restart of Unit 1 or June 30, 1989. This will reduce the Company's cash flow through the agreement period by approximately $6.75 million per month. The suspension of collection from ratepayers will also serve to reduce earnings per share through the agreement period by approximately $.03 per month.

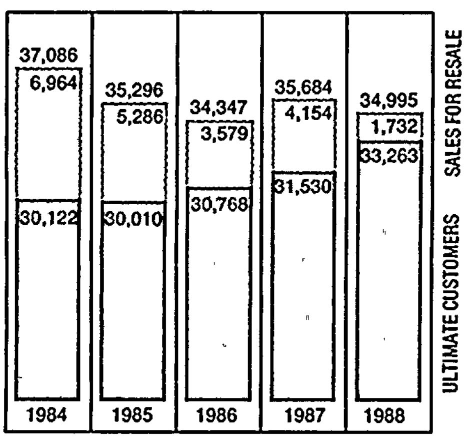
If Unit 1 is not returned to service by June 30, 1989, the parties to the interim agreement will be free to seek an extension of interim relief in whatever form they think appropriate. The Company cannot predict what form an extension of interim relief might take, if sought, or the resultant impact on the Company's financial condition, results of operations or external financing requirements. However, should the outage be extended beyond June 30, 1989 and interim relief is secured in essentially the same form, earnings would be adversely affected by approximately $.07 to $.09 per month (approximately $9.5 million to $12.3 million per month reduction in cash flow) dependent upon the level of replacement power costs absorbed by the Company through the normal operation of the fuel adjustment clause, the amount of incremental expenses necessitated by an extension of the outage and the continued suspension of collection of replacement power costs billed to customers under the fuel adjustment clause. These amounts exclude expenditures to be incurred in 1989 relative to the long-term nuclear improvement program, which will exert additional upward pressure on expenses.

The Company is unable to predict the results of the PSC's prudence investigation, what sanctions, if any, may ultimately be imposed and the adverse impact on the Company's financial condition, results of operations or level of retained earnings which might result if any such sanctions are imposed.

The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1988. It may not be indicative of future operations or earnings. It should be read in conjunction with the Notes to Consolidated Financial Statements and other financial and statistical information appearing elsewhere in this report.

Electric revenues increased $247.3 million or 11.8% over the three-year period. This increase results primarily from increased sales to ultimate consumers reflecting a combination of weather-related sales and load growth in the Company's service territory, base rate increases and the recording of unbilled electric revenues in accordance with the Stipulation Agreement, offset in part by decreased sales to other electric systems, as indicated in the table below:

ELECTRIC SALES Millions of Kw-hrs.

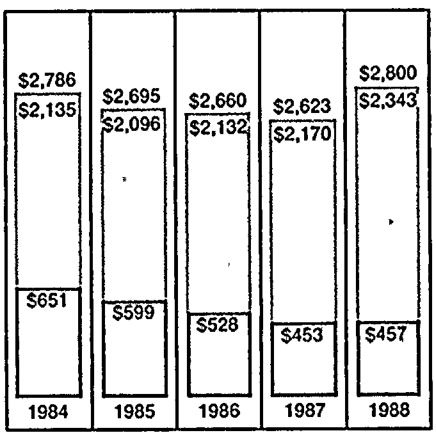


Electric revenues	Increase (decrease) from prior year *In millions of dollars* 1988	1987	1986	Total
Increase in base rates	$ 12.9	$ 49.7	$ 52.3	$114.9
Fuel and purchased power cost revenues	39.8	(53.8)	12.6	(1.4)
Sales to ultimate consumers	82.0	43.4	61.5	186.9
Sales to other electric systems	(57.8)	22.2	(100.3)	(135.9)
Unbilled electric revenues	62.5	—	—	62.5
Miscellaneous operating revenues	34.1	(23.1)	9.3	20.3
	$173.5	$ 38.4	$ 35.4	$247.3

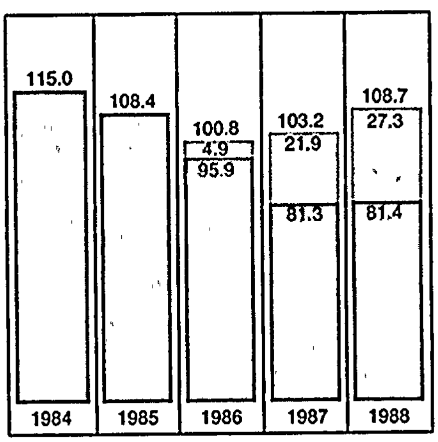
On March 12, 1986, the PSC approved a 2.1% electric rate increase to provide the Company additional annual revenues of $39,974,000, based on (i) forecast sales for the twelve months ended March 31, 1987, (ii) a 13.5% return on common equity and (iii) the inclusion of $680 million of Construction Work in Progress (CWIP) in electric rate base. The new rates were put into effect on March 17, 1986. On August 23, 1986, in connection with a second-stage filing involving this rate decision, the PSC approved additional annual electric revenues of $7,475,000 for items which were not considered in the March 1986 decision.

On March 13, 1987, the PSC approved a 4.0% electric rate increase to provide the Company additional annual revenues of $74,898,000 based on (i) forecast sales for the twelve months ended March 31, 1988, (ii) a 13.0% return on equity, and (iii) the inclusion of $1.625 billion of CWIP in electric rate base ($1.5 billion relating to Unit 2). The new rates, put into effect on March 16, 1987, reflect tax law changes of the Tax Reform Act of 1986 and a reduction to 13.0% from the 14.0% return on equity requested by the Company. No adjustment to gas rates was requested by the Company in connection with either of these rate decisions.

TOTAL ELECTRIC AND GAS OPERATING REVENUES Millions of dollars



GAS SALES Millions of dekatherms



Rate action initiated in 1987 sought $119.5 million (5.8%) additional electric revenues based upon forecast operations for the rate year ending June 30, 1989 and a 14.25% return on equity. The Company, as discussed above, reached a negotiated resolution of this request which resulted in, among other things, no increase in base electric rates through June 30, 1990. As a result of the continuing effects of the events discussed above and other factors, the Company will need to seek additional electric rate relief to become effective in July 1990. The form and extent of such rate relief is currently being considered.

Changes in fuel and purchase power cost revenues are generally margin-neutral while sales to other utilities, based upon regulatory sharing mechanisms, generally result in low margin contribution. Thus, fluctuations in these revenue components do not have a significant impact on net operating income.The Company was permitted to recognize in earnings unbilled electric revenues in an amount equal to the revenue required to amortize $39 million of the Company's investment in the discontinued Lake Erie Generation Station and to recoup other specified costs, therefore the effect of accrual of unbilled electric revenues on net operating income was minimal. Included in fuel and purchased power cost revenues is approximately $75.9 million of replacement power costs associated with the Unit 1 outage.

Electric kilowatt-hour sales were 35.0 billion in 1988, a decrease of 1.9% from 1987 and an increase of 1.9% from 1986. The 1988 decrease reflects increased sales in all customer classifications, offset by a substantial decline in sales to other electric systems caused by unfavorable price competition in the wholesale energy market. (See Electric and Gas Statistics—Electric Sales appearing on page 38). Details of the changes in electric revenues and kilowatt-hour sales by customer group are highlighted in table below:

	1988	%Increase (decrease) from prior year					
	% of Electric	1988		1987		1986	
Class of service	Revenues	Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	34.4%	9.0%	4.6%	5.2%	3.2%	8.5%	4.3%
Commercial	35.3	5.7	4.3	2.1	3.3	8.2	4.7
Industrial	19.5	5.2	7.5	(3.0)	1.1	2.6	(0.8)
Municipal service	1.8	1.5	.8	(1.0)	0.4	4.6	(2.9)
Total to ultimate consumers	91.0	6.7	5.5	2.0	2.5	6.9	2.5
Other electric systems	2.6	(49.0)	(58.3)	23.2	16.1	(51.1)	(32.3)
Miscellaneous	6.4	179.2	—	(30.0)	—	13.7	—
Total	100.0%	8.0%	(1.9)%	1.8%	3.9%	1.7%	(2.7)%

Gas revenues decreased $141.7 million or 23.7% over the three-year period. As shown by the table below, this decrease is attributable to lower costs for purchased gas, coupled with certain large commercial and industrial customers now purchasing gas directly from producers and only having the Company transport the gas to them, offset partly by increased residential sales. Rates for transported gas generally yield margins similar to margins on gas sold directly by the Company. As a result, substantial decreases in gas revenues caused by the migration of customers to the transported gas classification have not had a significant impact on earnings from gas operations. Also, changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year *In millions of dollars*			
Gas revenues	1988	1987	1986	Total
Increase in base rates	$ —	$ —	$ 3.0	$ 3.0
Purchased gas adjustment clause revenues	(6.2)	(12.0)	(20.0)	(38.2)
Increase (decrease) in residential sales	18.9	(8.8)	13.2	23.3
Increase (decrease) in commercial and industrial sales	(15.1)	(61.9)	(68.6)	(145.6)
Transportation of customer-owned gas	2.3	9.3	2.2	13.8
Miscellaneous operating revenues	3.6	(1.8)	0.2	2.0
	$ 3.5	$ (75.2)	$ (70.0)	$ (141.7)

Gas sales, excluding transportation of customer-owned gas, were 81.4 million dekatherms in 1988, a slight increase from 1987 (see Electric and Gas Statistics—Gas Sales appearing on page 38). The increase for 1988 reflects a 6.3% increase in sales in the residential class reflecting a combination of weather-related sales and load growth offset by a 41% decrease in sales in the industrial class because of competition from oil and the ability of customers to purchase gas directly from producers. The Company transported 27.2 million dekatherms for customers purchasing gas directly from producers and expects a continued increase in such transportation activities. To the extent the increase is due to existing customers electing to purchase gas directly from suppliers, there will be a corresponding reduction in gas revenues. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

Class of service	1988 % of Gas Revenues	% Increase (decrease) from prior year 1988 Revenues	1988 Sales	1987 Revenues	1987 Sales	1986 Revenues	1986 Sales
Residential	63.3%	3.2%	6.3%	(5.6)%	(2.8)%	6.0%	4.4%
Commercial	26.2	(1.0)	1.8	(15.2)	(13.6)	(3.3)	0.8
Industrial	4.2	(36.1)	(41.0)	(56.6)	(53.5)	(48.7)	(46.7)
Total to ultimate consumers	93.7	(0.7)	.6	(15.2)	(14.5)	(11.8)	(10.9)
Other gas systems	2.1	6.4	(13.8)	(38.4)	(32.8)	(23.5)	(23.6)
Transportation of customer-owned gas	3.0	19.8	24.6	414.8	349.1		
Miscellaneous	1.2	189.9	—	(49.7)	—	68.6	—
Total	100.0%	0.8%	5.3%	(14.2)%	2.3%	(11.7)%	(11.5)%

In January 1988, the PSC approved a gas rate settlement proposed by the Company and interested parties, which will maintain current gas base rates through June 1990 while refunding approximately $5.7 million to gas customers to reflect changes resulting principally from the Tax Reform Act of 1986. In accordance with this agreement, the Company will be allowed to retain all gas segment earnings up to a 13.0% return on equity and 30% of any earnings in excess of 13.0%. The Company expects to seek additional gas rate relief to become effective in July 1990, and is currently considering the form and extent of such rate relief.

In 1988, electric fuel and purchased power costs increased to $704 million from $666 million in 1987 and $672 million in 1986. The increase in 1988 is the result of a $58.5 million increase in fuel and purchased power costs incurred offset by a $20.0 million net decrease in costs deferred and recovered through the operation of the fuel adjustment clause. Included in electric fuel and purchased power costs for 1988 is $93.1 million of replacement power costs associated with the Unit 1 outage, of which $75.9 million was recovered from ratepayers through the fuel adjustment clause. Although generation and kilowatt hour purchases decreased 3.2%, fuel and purchased power costs incurred increased because of the use of higher cost fossil-fired generation to replace nuclear generation due to the outage at Unit 1 during 1988. (see Electric and Gas Statistics—Electricity Generated and Purchased appearing on Page 38).

The total cost of gas purchased decreased 1.1% in 1988, 20.8% in 1987, and 17.8% in 1986. The decrease for 1988 is the result of a 1.2% increase in dekatherms purchased to meet customer demand, offset by lower rates charged by the Company's principal supplier and favorable spot market purchases and a decrease in purchased gas costs recognized and recovered through the purchased gas adjustment clause. In 1988, the Company purchased 37% of its gas supply requirements on the spot market, the maximum allowable under its contract with its principal supplier. The Company's net cost per dekatherm purchased decreased to $3.19 in 1988 from $3.27 in 1987 and $3.52 in 1986.

Through the energy and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric fuel adjustment clause provides for partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a specific portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. In December 1987, the PSC established a proceeding to examine the operation of the existing fuel adjustment clause. Also, as discussed above, the Company will, for a portion of 1989, suspend collection of $225,000 per day in accordance with an interim relief agreement relating to replacement power costs occasioned by the Unit 1 outage. (See Note 10 of Notes to Consolidated Financial Statements.)

Other operation and maintenance expenses increased $120.2 million or 22.1% in 1988, after having decreased slightly in 1987 and increasing 7.6% in 1986. This substantial increase results primarily from Unit 2 becoming commercial in 1988 and increased costs resulting from the continuing outage at Unit 1 and the mid-cycle outage at Unit 2. Further, the Company embarked on a number of customer service, generating station life-extension and nuclear improvement programs in 1988 which increased the level of expenses as compared to 1987. Increases in 1986 were primarily the result of increases in maintenance costs associated with the Company's electric distribution system and scheduled costs coincident with the refueling of Unit 1.

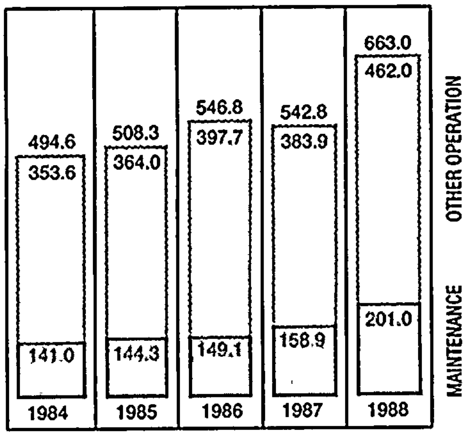
Depreciation and amortization expense for 1988 increased 15.6% over 1987 and 17.3% over 1986, principally from Unit 2 becoming commercial.

Net Federal and foreign income taxes for 1988 decreased as a result of a reduction in taxable income and the statutory tax rate. The increase in taxes other than income taxes in the three year period is due principally to higher property taxes resulting from property additions and the reflection of Unit 2 taxes that are now being charged to operations.

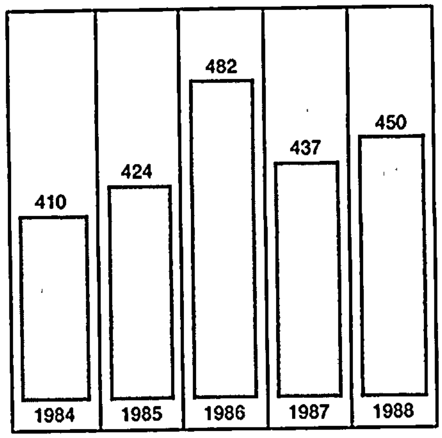
Other income and deductions, excluding Federal income taxes, increased $166 million from 1987. This increase is primarily the result of the recognition in 1987 of $218 million of disallowed plant costs (net of tax) offset by a $15 million decrease in AFC and a decrease of other items of $37 million. The decrease in AFC is attributable to lower AFC rates, lower interest bearing plant balances as a result of the write-off of disallowed plant costs and increased CWIP in rate base through March 1988. The decrease in other items (net) is primarily the result of the recording of the $14 million refund to customers in accordance with the Stipulation Agreement, coupled with a $11.1 million decline in earnings during 1988 by Opinac Energy Corporation primarily because of nonrecurring gains recognized in 1987 from the sale of the St. Lawrence Power Company and certain other investments.

Net interest charges increased $7.6 million in 1988, primarily the result of a $4.4 million decrease in the credit for the borrowed funds component of AFC. Dividends on Preferred Stock decreased $2.9 million in 1988 as a result of net reductions in amounts outstanding. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, decreased to 8.92% and 7.90%, respectively, in 1988, from 8.99% and 7.93%, respectively, in 1987, as a result of the Company's refinancing efforts.

MAINTENANCE AND OTHER OPERATION EXPENSE Millions of dollars



TOTAL TAXES INCLUDING INCOME TAXES Millions of dollars



Effects of Changing Prices. The rate of inflation continued to be moderate in 1988. The Company is especially sensitive to inflation because of the amount of capital it must raise to finance its construction program and because its prices are regulated using a rate base that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different from the present. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its utility plant and equipment for the historical cost value at which they are recorded on the books. In addition, the Company would probably not replace these assets with identical ones due to technological advances and regulatory changes which have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the current cost of providing service. The Company, however, will seek additional revenue to cover the costs of maintaining service as assets are replaced.

During a period of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance utility plant. Since the depreciation on utility plant is limited to the recovery of historical costs, the Company does not have the opportunity to realize a holding gain on debt and is limited to recovery only of the embedded cost of debt capital. The following table presents selected financial data restated for the effects of changing prices in average 1988 dollars.

	1988	1987	1986
Operating Revenues ($000's)	$2,800,453	$2,723,620	$2,862,840
Gain from decline in purchasing power on net amounts owed ($000's)	$ 145,124	$ 153,056	$ 39,191
Per Common Share:			
Cash dividends declared	$ 1.20	$ 1.70	$ 2.24
Market price at year end	$ 13.00	$ 12.46	$ 18.02
Average Consumer Price Index	353.4	340.4	328.4

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Financial Position. The Company's capital structure and earnings base has been weakened by the 1987 write-off of Unit 2's disallowed costs. The capital structure at December 31, 1988 was 55.1% long-term debt, 10.7% preferred stock and 34.2% common equity as compared to 47.0%, 10.5% and 42.5%, respectively, at December 31, 1986—prior to such write-off, and 54.9%, 12.0% and 33.1%, respectively, at December 31, 1987. Book value of the common stock was $13.87 per share at December 31, 1988 as compared to $20.23 per share at December 31, 1986 and $13.82 per share at December 31, 1987.

The ratio of earnings to fixed charges for 1988 was 2.10. This is an improvement from the 1987 ratio of 1.65 (excluding the cumulative effect of adoption of SFAS No. 90) which was negatively impacted by the Unit 2 write-off. The ratio in 1986 was 2.98. The Unit 2 write-off and its resultant impact on the Company's earnings capability necessitated a reduction in the common stock dividend rate in 1987 to a current annual level of $1.20 per share (See also: Market Price of Common Stock and Related Stockholder Matters).

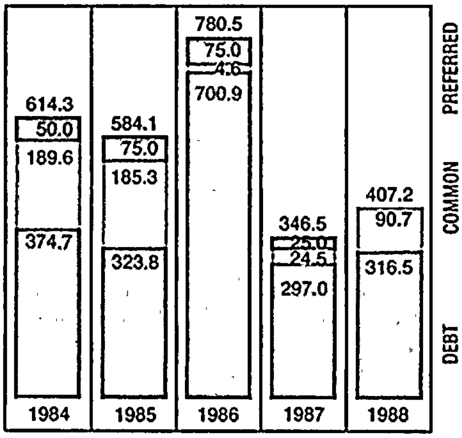
Construction and Other Capital Requirements. The Company's overall requirements consist of amounts for the Company's construction program, working capital needs, maturing debt issues and sinking fund provisions on outstanding debt and preferred stock and have been affected by the Company's efforts in recent years to lower capital costs through refinancing. Using the maximum rates payable on variable rate securities, the year-end average cost of long-term and preferred dividend rates including sinking fund requirements and current maturities were 9.87% and 9.15%, respectively, representing the lowest such average capital costs since 1985. Total capital needs have been decreasing since 1987 as Unit 2 approached completion and as budgeted construction expenditures were curtailed. Annual expenditures for the years 1986-1988 for construction and nuclear fuel, including related AFC and overheads capitalized, were $774.1 million, $447.2 million and $353.9 million, respectively.

The 1989 estimate for construction additions, overheads capitalized and nuclear fuel, and excluding AFC, is approximately $429 million, of which 54% is expected to be funded by internal sources. Mandatory and optional debt and preferred stock retirements and other requirements are expected to add approximately another $117 million to the Company's capital requirements, for a total of $546 million. Current estimates of total capital requirements for the years 1990-1993 are $570 million, $521 million, $633 million, and $529 million, respectively. Such estimates take into consideration, among other things, the 1988 Stipulation Agreement and the effects of the outage at Unit 1 through June 30, 1989. Future capital requirements rely on life-extension of the Company's existing facilities and the proposed competitive bidding procedures in New York State for independent power production to satisfy future capacity requirements. Therefore, they do not include any current plans by the Company to construct new base load generating facilities.

Also, in connection with the Company's Restart Action Plan for Unit 1 and its overall nuclear improvement program, operating expenditures are expected to increase over presently forecasted levels.

The Nuclear Regulatory Commission (NRC) has issued regulations which could require the Company to accelerate funding requirements for decommissioning of its nuclear units by amounts which cannot currently be determined. The Company currently uses the internal reserve method of accumulating decommissioning costs, which does not require internal segregation of funds collected. The NRC regulations require the establishment of an external trust to accumulate decommissioning costs, which will decrease the Company's sources of cash in the fu-

ANNUAL EXTERNAL FINANCING BY TYPE Millions of dollars



ture. The impact on capital requirements resulting from the NRC regulations could be substantial considering the Company's current forecast of decommissioning costs and the recoveries of such costs currently allowed by the PSC (see Note 10 of Notes to Consolidated Financial Statements).

Liquidity and Capital Resources. Cash flows to meet the Company's requirements for operating, investing and financing activities during the past three years are reported in the Consolidated Statement of Cash Flows on page 21.

During 1988, the Company raised approximately $407.2 million through external sources, consisting of $269.8 million of debt, $90.7 million of common stock from the issuance of 6,679,672 new shares through the Dividend Reinvestment and Employee Stock Plans and a net increase of $46.7 million of short-term debt and intermediate term bank revolving credit obligations. The Company also completed $12.6 million of capital lease financing and raised $100 million internally through the sale of a portion of its accounts receivable.

The Company expects external financing of approximately $297 million in 1989, which reflects the cash flow impact of the Interim Relief Agreement relative to the Unit 1 outage. The level of external financing could be substantially increased should the company be required to fund its guarantee of $150 million of tax-exempt obligations of Long Island Lighting Company (see Note 11 of Notes to Consolidated Financial Statements) or should the Unit 1 outage extend beyond June 30, 1989. With respect to the guarantee obligation, the Company has credit facilities in place to fund its obligation if necessary. To minimize the dilutive effect on earnings per share of the issuance of new common stock, the Company intends to temporarily suspend sales of new common stock under the Dividend Reinvestment and Employee Stock Plans effective during the first quarter of 1989 but expects to purchase its requirements on the open market. The anticipated amount of external financing in 1989 reflects this decision. Although external financing plans for 1990 to 1993 have not been finalized, the aggregate level of financing during this four year period is expected to be substantially greater than previous estimates reflecting, among other things, the substantial concerns relating to the Company's nuclear operations, the potential additional requirements to meet the NRC's new decommissioning regulations, the effects of rate regulation and the need to improve the Company's financial position. The nature, timing and amount of such future financings will also depend, in part, on construction expenditure levels, duration of and costs associated with the Unit 1 outage, retirements of securities, timeliness and adequacy of rate relief, the level of internally generated funds and dividend payments, the availability and cost of capital and the ability of the Company to meet its interest and preferred stock dividend coverage requirements, to satisfy legal requirements and restrictions in governing instruments and to maintain an adequate credit rating.

The Company believes that traditionally available sources of financing should be sufficient to satisfy the Company's external financing needs during this period. As of December 31, 1988, under the applicable earnings test set forth in the indenture, the Company would be permitted to issue up to $1.35 billion of First Mortgage Bonds assuming a 10.75% interest rate and the existence of sufficient Additional Property, as defined in the Company's indenture, to secure that level of indebtedness. However, based on the amount of Additional Property currently certified and available, the Company could only issue approximately $468 million of First Mortgage Bonds. In addition, the Company may issue approximately $972 million of First Mortgage Bonds at December 31, 1988 on the basis of retired bonds without regard to the earnings test. $100 million of Preference Stock is currently authorized for sale if needed. The Company does not expect to be able to issue additional Preferred Stock until 1991, except for refunding issues, as a result of a restrictive provision in the Company's charter. The Company will also continue to explore and utilize, as appropriate, other methods of raising funds including the sale of additional accounts receivable.

The Company's ratings at December 31, 1988 on its secured and unsecured debt respectively, were:

	Secured	Unsecured	Preferred
Standard & Poors Corporation	BBB+	BBB	BBB
Moody's Investors Service	Baa1	Baa2	baa2
Duff & Phelps	8	9	9
Fitch Investors Services	BBB	BBB−	BBB−

On February 7, 1989, Moody's Investors Service downgraded the Company's secured and unsecured debt ratings to Baa2 and Baa3, respectively and its preferred stock rating to baa3. On February 8, 1989, Duff & Phelps lowered its ratings on the Company's secured debt and unsecured debt to 9 and 10, respectively. Further, Duff & Phelps lowered its rating on the Company's preferred stock from 9 to 12, or below investment grade. Reductions of the Company's credit ratings, and the attendant adverse effect on the interest or dividend rates that may be required in future issues of its securities, especially if ratings were to fall or remain below investment grade, may reduce the Company's financing flexibility and adversely affect its capital structure and financial position.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a continuing basis. Bank credit arrangements which, at December 31, 1988, totaled $335 million, (including $150 million of revolving credit and term loan agreements, $85 million in lines of credit and a $100 million Bankers Acceptance Facility Agreement) are used by the Company to enhance flexiblility as to the type and timing of its long-term security sales. Such credit arrangements were reduced in 1988 from $555 million at December 31, 1987, to enable the Company to better control its borrowing costs with less stringent terms than were contained in previous bank credit agreements. In January 1989, the Company arranged a short-term $50 million line of credit which is secured by equipment.

The unsecured debt limitation imposed by the Company's charter is 10% of consolidated capitalization plus $50 million, which, as of January 1, 1989, equates to approximately $565 million and against which the Company has outstanding unsecured debt of $456 million. The Company intends to negotiate additional credit facilities that would enable it to borrow unsecured debt up to the permissible limit and to add other borrowing capability on a secured basis as required.

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1988	1987
ASSETS		
Utility plant, at original cost *(Note 1):*		
Electric plant	$6,497,398	$4,777,519
Nuclear fuel *(Note 3)*	404,686	408,427
Gas plant	611,671	577,201
Common plant	138,226	138,360
Construction work in progress *(Note 10)*	315,644	1,789,562
Total utility plant	7,967,625	7,691,069
Less accumulated depreciation and amortization	2,090,170	1,913,687
Net utility plant	5,877,455	5,777,382
Other property and investments	155,257	115,076
Current assets:		
Cash, including time deposits of $11,335 and $9,017, respectively	19,027	29,791
Accounts receivable (less allowance for doubtful accounts of $3,600)*(Note 11)*	228,914	305,028
Unbilled electric revenues *(Note 1)*	126,000	—
Materials and supplies, at average cost:		
Coal and oil for production of electricity	47,382	47,863
Other	76,950	71,336
Prepayments:		
Taxes	39,914	30,971
Other	26,642	21,624
	564,829	506,613
Deferred debits:		
Unamortized debt expense	128,520	125,108
Deferred recoverable energy costs	32,239	8,436
Deferred finance charges *(Note 1)*	239,880	202,044
Other	77,861	59,439
	478,500	395,027
	$7,076,041	$6,794,098

At December 31,	1988 (In thousands of dollars)	1987
CAPITALIZATION AND LIABILITIES		
Capitalization *(Note 7)*:		
Common stockholders' equity:		
Common stock, issued 135,633,096 and 128,953,424 shares, respectively	$ 135,633	$ 128,953
Capital stock premium and expense	1,640,593	1,548,826
Retained earnings	105,168	103,739
	1,881,394	1,781,518
Non-redeemable preferred stock	290,000	290,000
Redeemable preferred stock	295,510	355,490
Long-term debt	2,995,748	2,903,921
Total capitalization	5,462,652	5,330,929
Current liabilities:		
Short-term debt *(Note 4)*	108,000	50,005
Long-term debt due within one year	110,571	77,508
Sinking fund requirements on redeemable preferred stock *(Note 7)*	17,980	14,980
Accounts payable	219,798	164,350
Payable on outstanding bank checks	82,279	48,253
Customers' deposits	9,985	9,680
Accrued taxes	16,132	19,761
Accrued interest	71,842	70,411
Accrued vacation pay	29,904	29,862
Due to cotenants under Cotenant Agreement *(Note 10)*	—	171,100
Other	39,640	44,418
	706,131	700,328
Deferred credits:		
Mandated refunds to customers	5,613	36,167
Accumulated deferred Federal income taxes	562,811	476,768
Deferred finance charges *(Note 1)*	239,880	202,044
Unbilled electric revenues *(Note 1)*	63,534	—
Other	35,420	47,862
	907,258	762,841
Commitments and contingencies *(Notes 3, 10 and 11)*	—	—
	$7,076,041	$6,794,098

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	1988	In thousands of dollars 1987	1986
Operating revenues:			
Electric	$2,343,732	$2,170,191	$2,131,833
Gas	456,721	453,239	528,486
	2,800,453	2,623,430	2,660,319
Operating expenses:			
Operation:			
Fuel for electric generation	360,373	339,382	319,834
Electricity purchased	343,511	326,152	352,126
Gas purchased	265,033	268,099	338,634
Other operation expenses	462,060	383,874	397,714
Maintenance	200,969	158,939	149,124
Depreciation and amortization	182,209	157,631	155,311
Federal and foreign income taxes	134,451	195,472	211,237
Other taxes	329,869	308,483	295,165
Amortization of investment in generating station project *(Note 2)*	39,813	—	—
	2,318,288	2,138,032	2,219,145
Operating income	482,165	485,398	441,174
Other income and deductions:			
Allowance for other funds used during construction	5,149	20,563	121,932
Federal income taxes	13,587	17,622	32,293
Current year effect of adoption of SFAS No. 90 *(Note 10):*			
Disallowed plant costs	—	(268,400)	—
Related income taxes	—	50,400	—
Other items (net)	(25,758)	10,947	37,539
	(7,022)	(168,868)	191,764
Income before interest charges	475,143	316,530	632,938
Interest charges:			
Interest on long-term debt	264,866	264,472	264,054
Other interest	7,336	4,587	14,880
Allowance for borrowed funds used during construction	(5,873)	(10,315)	(43,861)
	266,329	258,744	235,073
Income before cumulative effect of accounting change	208,814	57,786	397,865
Cumulative effect on prior years of adoption of SFAS No. 90 *(Note 10)*	—	(615,000)	—
Net income (loss)	208,814	(557,214)	397,865
Dividends on preferred stock	49,157	52,017	53,817
Balance available for common stock	159,657	(609,231)	344,048
Dividends on common stock	158,228	208,881	264,312
	1,429	(818,112)	79,736
Retained earnings at beginning of year	103,739	921,851	842,115
Retained earnings at end of year	$ 105,168	$ 103,739	$ 921,851
Average number of shares of common stock outstanding *(in thousands)*	131,853	127,435	127,076
Per average share of common stock:			
Balance available for common stock before cumulative effect of accounting change	$ 1.21	$ 0.5	$ 2.71
Cumulative effect on prior years of adoption of SFAS No. 90 *(Note 10)*	—	(4.83)	—
Balance available for common stock	$ 1.21	$ (4.78)	$ 2.71
Dividends paid	$ 1.20	$ 1.64	$ 2.08
Proforma amounts assuming effects of adoption of SFAS No. 90 applied retroactively:			
Balance available for common stock	$ —	$ 5,769	$ 16,048
Balance available per share of common stock	$ —	$ .05	$ .13

( ) Denotes deduction

Consolidated Statements of Cash Flows
Increase (Decrease) in Cash

For the year ended December 31,	1988	1987 (In thousands of dollars)	1986
Cash flows from operating activities:			
Net income (loss)	$208,814	$ (557,214)	$ 397,865
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect on prior years of adoption of SFAS No. 90	—	615,000	—
Disallowed plant costs	—	268,400	—
Depreciation and amortization	222,022	157,631	155,311
Amortization of nuclear fuel	16,362	28,748	18,257
Provision for deferred Federal income taxes	82,477	97,934	133,743
Allowance for other funds used during construction	(5,149)	(20,563)	(121,932)
Deferred recoverable energy costs	(23,803)	1,499	22,585
Gain on sale of investments	—	(13,000)	—
Unbilled electric revenues	(62,466)	—	—
Decrease in mandated refunds to customers	(30,554)	(27,062)	(16,771)
(Increase) decrease in net accounts receivable	76,114	(15,678)	(5,388)
(Increase) decrease in materials and supplies	(3,000)	(3,452)	17,848
Increase (decrease) in accounts payable and accrued expenses	46,727	38,667	(29,270)
Increase (decrease) in accrued interest and taxes	(2,198)	11,181	(4,726)
Changes in other assets and liabilities	(26,925)	(21,526)	(10,204)
Net cash provided by operating activities	498,421	560,565	557,318
Cash flows from investing activities:			
Construction additions	(349,823)	(409,068)	(736,242)
Nuclear fuel	(3,759)	(28,765)	(23,536)
Less: Allowance for other funds used during construction	5,149	20,563	121,932
Acquisition of utility plant	(348,433)	(417,270)	(637,846)
(Increase) decrease in materials and supplies	(2,133)	772	(4,463)
Increase (decrease) in accounts payable and accrued expenses	12,877	(6,334)	(11,864)
Sale of utility plant	—	—	128,000
Repayment of construction advances	—	—	92,847
Payments under Cotenant Agreement	(171,100)	—	—
Sale of LILCO General & Refunding Bonds	—	—	140,000
(Increase) decrease in other investments	(41,200)	(22,823)	72,596
Cotenant prepayments to Nine Mile Point Nuclear Unit No. 2 project fund	—	(331)	(83,808)
Other	9,197	12,664	(10,675)
Net cash used in investing activities	(540,792)	(433,322)	(315,213)
Cash flows from financing activities:			
Proceeds from sale of common stock	90,683	24,459	4,603
Proceeds from sale of preferred stock	—	25,000	75,000
Sale of first mortgage bonds	200,000	100,000	500,000
Issuance of other long-term debt	69,800	270,060	98,900
Redemption of preferred stock	(56,980)	(62,380)	(60,050)
Reductions of long-term debt	(137,193)	(273,005)	(439,315)
Net change in short-term debt and revolving credit agreement	46,736	(72,987)	101,976
Dividends paid	(177,168)	(268,591)	(320,255)
Other	(4,271)	(15,987)	(71,918)
Net cash provided by (used in) financing activities	31,607	(273,431)	(111,059)
Net increase (decrease) in cash	(10,764)	(146,188)	131,046
Cash at beginning of year	29,791	175,979	44,933
Cash at end of year	$ 19,027	$ 29,791	$ 175,979
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$299,351	$284,348	$ 301,224
Income taxes	42,348	44,479	47,770
Supplemental schedule of noncash investing and financing activities:			
Net increase in capital lease obligations	$ 227	$ 9,397	$ 14,284

Notes to Consolidated Financial Statements

NOTE 1. Summary of Significant Accounting Policies

The Company is subject to regulation by the New York State Public Service Commission (PSC) and the Federal Energy Regulatory Commission (FERC) with respect to its rates for service and the maintenance of its accounting records. The Company's accounting policies conform to generally accepted accounting principles, as applied to regulated public utilities, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities.

Statement of Cash Flows: In November 1987, Statement of Financial Accounting Standards No. 95, (SFAS No. 95), "Statement of Cash Flows" was issued by the Financial Accounting Standards Board (FASB). The Company adopted SFAS No. 95 for the year ended December 31, 1988 and has restated the consolidated statements of changes in financial position for 1987 and 1986 to conform with the 1988 presentation of cash flows. The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated. Assets and liabilities of foreign subsidiaries are translated into U.S. dollars at the exchange rate in effect at the balance sheet date. Revenue and expense accounts are translated at the average exchange rate in effect during the year. Currency translation adjustments are recorded as a component of equity and do not have a significant impact on financial condition.

Utility Plant: The cost of additions to utility plant and of replacements of retirement units of property is capitalized. Cost includes direct material, labor, overhead and an allowance for funds used during construction (AFC). The cost of current repairs and maintenance is charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation.

Allowance for Funds Used During Construction: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect December 31, 1988 was 10.40%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the Interest Charges section and the Other Income and Deductions section, respectively, of the Consolidated Statement of Income.

Effective April 1985, pursuant to a PSC authorization, the Company discontinued accruing AFC on $320 million of construction work in progress (CWIP) for which a cash return was being allowed through inclusion in rate base of that portion of the investment in the Nine Mile Point Nuclear Station Unit No. 2 (Unit 2). This amount was increased to $680 million in April 1986 and $1,625 million (including $125 million of other CWIP) in April 1987. Amounts equal to the Unit 2's AFC which was no longer accrued on the CWIP included in rate base have been accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2. The balance in the deferred accounts, amounting to $239.9 million at December 31, 1988, await future ratemaking disposition by the PSC. A portion of the deferred credit could be utilized to reduce future revenue requirements over a period shorter than the life of Unit 2 with a like amount of deferred debit amortized and recovered in rates over the remaining life of Unit 2, as has been the experience of other New York State utilities.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting purposes, depreciation is computed on the straight-line basis using the average or remaining service lives by classes of depreciable property. In addition, certain costs associated with the discontinued Lake Erie Generating Station Project (see Note 2) were amortized over shorter periods as approved by the PSC. For Federal income tax purposes, the Company computes depreciation using accelerated methods and shorter allowable depreciable lives. Estimated decommissioning costs (costs to remove the plant from service in the future) for the Company's Nine Mile Point Nuclear Station Unit No. 1 and its share of decommissioning costs of Unit 2 are being recovered in rates through an annual allowance and charged to operations through depreciation charges (see Note 10).

Amortization of Nuclear Fuel: Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per kilowatt-hour of net generation, is based upon a contract with the U.S. Department of Energy. These costs are charged to operating expense and recovered from customers through base rates or through the fuel adjustment clause.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly. Although the Company commenced the accrual in 1988 of electric revenues for energy consumed and not billed at the end of the fiscal year, the impact of such accruals have not yet been fully recognized in the Company's results of operations in accordance with the Stipulation Agreement. Approximately $62.5 million of such accrued electric revenues is included in the results of operations for the year ended December 31, 1988, and the remainder is included in Deferred Credits. The amounts included in the Deferred Credit may be used to reduce future revenue requirements.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost increases in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed energy and purchased gas costs included in approved rate schedules. As a result of such periodic changes, a portion of energy costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the electric and gas adjustment clauses. However, the Company has been permitted to amortize and bill or credit such portions to customers, through the electric and gas adjustment clauses, over a specified period of time from the effective date of each change. The Company's electric fuel adjustment clause provides for partial pass-through of fuel cost fluctuations from amounts forecast with the Company absorbing a specific portion of increases or retaining a portion of decreases up to a maximum of $15 million per rate year (However, see Note 10 "Interim Agreement on Unit 1 Outage Replacement Power Costs").

Federal Income Taxes: In accordance with PSC requirements, the tax effect of book and tax timing differences is flowed through unless authorized by the PSC to be deferred. The Company provides deferred taxes on certain benefits realized from depreciation, on deferred energy and purchased gas costs, on nuclear fuel disposal costs accrued prior to April 1983, on nuclear generating plant decommissioning costs, on certain construction overheads and on certain other items (see Note 9). As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. In conformity with ratemaking practices of the PSC, the Company has not provided deferred taxes on the cumulative amount of approximately $1.6 billion of other tax deductions which include certain depreciation differences and various construction overheads deductible currently for tax purposes and capitalized for accounting and ratemaking purposes. The Company has claimed investment tax credits and deferred the benefits of such credits as realized in accordance with PSC directives. Deferred investment credit is amortized to Other Income and Deductions over the useful life of the underlying property. For purposes of computing capital cost recovery deductions and normalization, the asset basis has been reduced by all or a portion of the credit claimed consistent with then current tax laws. The imputed tax benefit of the borrowed funds component of AFC on transitional property is recorded in Other Income and Deductions.

The FASB has issued Statements of Financial Accounting Standards No. 96 and No. 100 (SFAS No. 96 and No. 100) "Accounting for Income Taxes" which require the adoption of SFAS 96 for fiscal years beginning after 1989. The pronouncement continues the present comprehensive inter-period tax allocation rules, but shifts to the use of the liability method for accounting for deferred taxes rather than the deferred method required under APB Opinion No. 11. Regulated utilities are not exempt from the provisions of SFAS No. 96, which specifically prohibits net-of-tax accounting and reporting and requires (i) recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate and (ii) adjustment of a deferred tax liability or asset for an enacted change in tax laws or rates. However, any impact of the pronouncement should be considered within the ratesetting environment. The adoption of the requirements of SFAS No. 96 is not expected to significantly impact the Company's financial condition or results of operations.

Amortization of Debt Issue Costs: The premium or discount and debt expenses on long-term debt issues and on certain debt retirements prior to maturity, are amortized ratably over the lives of the related issues and included in interest on long-term debt (see Note 7).

NOTE 2. Depreciation and Amortization

The total provision for depreciation and amortization, including amounts charged to clearing accounts, was $183,385,000 for 1988, $158,761,000 for 1987 and $156,494,000 for 1986. The 1988 provision excludes approximately $39,800,000 resulting from the amortization of costs associated with the discontinued Lake Erie Generating Station Project (LEGS) in accordance with the Stipulation Agreement (see discussion of the Stipulation Agreement in Management's Discussion and Analysis of Financial Condition and Results of Operations). The remaining unrecovered cost of LEGS of approximately $6,200,000, representing a portion of carrying charges accrued on LEGS, was charged primarily against Other Income and Deductions for the year ended December 31, 1988. The percentage relationship between the total provision for depreciation and average depreciable property was 2.7% in 1988 and 3.0% in 1987 and 1986. The Company performs depreciation studies on a continuing basis and, upon approval by the PSC, periodically adjusts the rates of its various classes of depreciable property.

NOTE 3. N M Uranium, Inc.

During 1976, through a wholly-owned subsidiary, N M Uranium, Inc. (NMU), the Company purchased a 50 percent undivided interest in uranium deposits and associated mining equipment to be held by a jointly-owned mining venture. Acquisition of this interest was made primarily to provide a more assured future supply of nuclear fuel. Mining operations are now complete and site restoration activities are underway. The investment in the subsidiary, which includes costs incurred since acquisition and AFC accrued through March 31, 1981, has been reduced by the proceeds from the sale of uranium, net of tax, transfers of uranium to the Company and write-offs of portions of the Company's investment, and is included in the consolidated financial statements as part of the nuclear fuel component of utility plant. Such investment, net of valuation reserves of $20.5 million and $13.0 million at December 31, 1988 and 1987, respectively, totaled $44.9 million at December 31, 1988 and $52.5 million at December 31, 1987.

In connection with the Company's rate decisions in March 1984, and March 1986 and the Stipulation Agreement, the PSC has allowed, as the cost of approximately 1,313,000 lbs. of NMU uranium utilized in the 1984, 1986 and current reloads of the Company's Nine Mile Point Nuclear Unit No. 1 and approximately 107,000 lbs. utilized for a portion of the initial core at Nine Mile Point Nuclear Unit No. 2, a price which represents the average United States delivery price for the year of transfer, as reported by the U.S. Department of Energy (DOE). The total allowed value of these transfers using DOE prices is approximately $45.0 million while the Company's cost is approximately $63.0 million. The differential between the Company's cost of this NMU uranium and that amount allowed to be recovered in rates charged to customers has been deferred subject to the PSC approval of the comparison of cost to market on an aggregate basis over the life of the project and is reflected in the Company's investment in NMU.

In October 1988, NMU transferred approximately 186,000 lbs. of uranium to the Company (with a cost of approximately $8.6 million) to be used in the 1990 refueling of Nine Mile Point Nuclear Unit No. 2. Although the allowable value for this material is expected to be the appropriate DOE price, such costs must still be reviewed in the Company's next rate proceeding. Approximately 955,000 pounds of uranium remain to be transferred, with the final transfer currently scheduled for 1991.

Based upon DOE's recently issued forecast which reflects a continued decline in average delivery prices from previous forecasts and the anticipated further decline in average delivery prices, the Company expects that based upon costs allowed in rates to date and the estimated value of remaining transfers, a minimum of $20.5 million of its investment in NMU may not be recoverable in rates. Accordingly, the Company has reduced the carrying value of such investment by $13 million in 1987 and $7.5 million in 1988. The Company can provide no assurance that all of its remaining investment in NMU will ultimately be recovered.

NOTE 4. Bank Credit Arrangements

At December 31, 1988, the Company had $335 million of bank credit arrangements with 30 banks. These credit arrangements consisted of $150 million in commitments under a Revolving Credit Agreement, $72 million in short-term commitments under Credit Agreements, $13 million in lines of credit and $100 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreement extends into 1991 and the interest rate applicable to borrowing is based on certain rate options available under the Agreement. All of the other bank credit arrangements are subject to review on an ongoing basis with interest rates negotiated at the time of use. The Company also issues commercial paper. Unused bank credit facilities are held available to support the amount of commercial paper outstanding, including amounts currently issued in connection with Interest Rate Exchange Agreements (see Note 7). The Revolving Credit Agreement contains representations which, if not met or re-negotiated, would prevent the Company from making new borrowings under such agreements. The Company is presently in compliance with these convenants and restrictions.

The Company pays fees for substantially all of its bank credit arrangements. The Bankers Acceptance Facility Agreement, which is used to finance the fuel inventory for the Company's generating stations, provides for the payment of fees only at the time of issuance of each acceptance. Additional bank credit arrangements in connection with the Company's guarantee of certain obligations of LILCO are discussed in Note 11.

In January 1989, the Company arranged a short-term $50 million line of credit which is secured by equipment.

Amounts outstanding under Interest Rate Exchange Agreements and Revolving Credit Agreements totaled $75 million at December 31, 1988 and are recorded as long-term debt.

The following table summarizes additional information applicable to short-term debt:

	In thousands of dollars	
At December 31:	1988	1987
Short-term debt:		
Commercial paper	$ 81,000	$ 27,000
Notes payable	—	5
Bankers acceptances	27,000	23,000
	$108,000	$ 50,005
Weighted average interest rate *(a)*	9.28%	7.46%
For year ended December 31:		
Daily average outstanding	$ 46,254	$ 51,256
Daily weighted average interest rate *(a)*	7.58%	6.63%
Maximum amount outstanding	$173,100	$154,000

(a) Excluding fees.

NOTE 5. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1988. The Company is required to provide its respective share of financing for any additions to the facilities. The Company's share of expenses associated with the facilities is included in the appropriate operating expenses in the Consolidated Statement of Income.

		In thousands of dollars		
	Percentage ownership	Utility plant	Accumulated depreciation	Construction work in progress
Roseton Steam Station Units No. 1 and 2 *(a)*	25	$ 83,823	$31,427	$ 92
Oswego Steam Station Unit No. 6 *(b)*	76	$262,108	$60,638	$1,742
Nine Mile Point Nuclear Station Unit No. 2 *(c)*	41	$1,468,075	$25,544	$ 530

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation, the operator of the plant (35%) and Consolidated Edison Company of New York, Inc. (40%).

(b) The Company is the operator. The remaining ownership interest is Rochester Gas and Electric Corporation (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

(c) The Company is the operator. The remaining ownership interests are Long Island Lighting Company (18%), New York State Electric and Gas Corporation (18%), Rochester Gas and Electric Corporation (14%), and Central Hudson Gas and Electric Corporation (9%). Output of Unit 2, which has a capability of 1,084,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

NOTE 6. Information Regarding the Electric and Gas Businesses

The Company is engaged in the electric and natural gas utility businesses. Certain information regarding these segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation or such common property have been allocated to the segments in accordance with practice established for regulatory purposes. Identifiable assets include net utility plant, unbilled electric revenues, materials and supplies, deferred finance charges, deferred recoverable energy costs and other deferred debits. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and other deferred debits.

	In thousands of dollars		
	1988	1987	1986
Operating revenues:			
Electric	$2,343,732	$2,170,191	$2,131,833
Gas	456,721	453,239	528,486
Total	$2,800,453	$2,623,430	$2,660,319
Operating income before taxes:			
Electric	$ 570,088	$ 637,120	$ 596,864
Gas	46,528	43,750	55,547
Total	$ 616,616	$ 680,870	$ 652,411
Pretax operating income, including AFC:			
Electric	$ 580,239	$ 667,610	$ 762,362
Gas	47,399	44,138	55,842
Total	627,638	711,748	818,204
Income taxes	134,451	195,472	211,237
Other income and deductions	(12,171)	(189,431)	69,832
Interest charges	272,202	269,059	278,934
Cumulative effect of accounting change	—	(615,000)	—
Net income *(loss)*	$ 208,814	$ (557,214)	$ 397,865
Depreciation and amortization:			
Electric	$ 167,566	$ 143,508	$ 141,663
Gas	14,643	14,123	13,648
Total	$ 182,209	$ 157,631	$ 155,311
Construction expenditures (including nuclear fuel):			
Electric	$ 304,515	$ 408,008	$ 734,348
Gas	49,344	39,222	39,714
Total	$ 353,859	$ 447,230	$ 774,062
Identifiable assets:			
Electric	$5,910,897	$5,626,117	$6,424,656
Gas	539,309	491,315	468,299
Total	6,450,206	6,117,432	6,892,955
Corporate assets	625,835	676,666	718,248
Total assets	$7,076,041	$6,794,098	$7,611,203

NOTE 7. Capitalization

CAPITAL STOCK

The following table summarizes the shares of capital stock authorized, issued and outstanding:

At December 31,	1988	1987	1986
Common stock, $1 par value:			
Authorized	150,000,000	150,000,000	150,000,000
Issued & outstanding	135,633,096	128,953,424	127,140,994
Preferred stock, $100 par value:			
Authorized	3,400,000	3,400,000	3,400,000
Issued & outstanding	2,644,000	2,927,000	3,260,000
Preferred stock, $25 par value:			
Authorized	19,600,000	19,600,000	19,600,000
Issued & outstanding	13,563,602	14,710,801	14,874,000
Preference stock, $25 par value:			
Authorized	4,000,000	4,000,000	4,000,000
Issued & outstanding	0	0	0

The table below summarizes changes in capital accounts for 1986, 1987 and 1988:

	Common Stock $1 par value		Preferred Stock $100 par value			Preferred Stock $25 par value			Capital Stock Premium and Expense (Net)*
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	
Balance January 1, 1986	126,928,340	$126,928	3,318,000	$210,000	$121,800(a)	14,044,000	$80,000	$271,100(a)	$1,519,577
Sales in 1986	60,354	61	—	—	—	3,000,000	—	75,000	(939)
Issued to stock purchase plans in 1986	152,300	152							2,821
Redemptions			(58,000)	—	(5,800)	(2,170,000)	—	(54,250)	437
Foreign currency translation adjustment									603
Balance December 31, 1986	127,140,994	127,141	3,260,000	210,000	116,000(a)	14,874,000	80,000	291,850(a)	1,522,499
Sales in 1987	—	—	—	—	—	1,000,000	—	25,000	(423)
Issued to stock purchase plans in 1987	1,812,430	1,812							22,442
Redemptions			(333,000)	—	(33,300)	(1,163,199)	—	(29,080)	577
Foreign currency translation adjustment									3,731
Balance December 31, 1987	128,953,424	128,953	2,927,000	210,000	82,700(a)	14,710,801	80,000	287,770(a)	1,548,826
Sales in 1988	—	—	—	—	—	—	—	—	—
Issued to stock purchase plans in 1988	6,679,672	6,680							83,937
Redemptions			(283,000)	—	(28,300)	(1,147,199)	—	(28,680)	672
Foreign currency translation adjustment									7,158
Balance December 31, 1988	135,633,096	$135,633	2,644,000	$210,000	$54,400(a)	13,563,602	$80,000	$259,090(a)	$1,640,593

**In thousands of dollars*

(a) Includes sinking fund requirements due within one year

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

The Company has certain issues of preferred stock which provide for optional redemption as follows:

At December 31,	In thousands of dollars 1988	1987	1986	Redemption price per share (Before adding accumulated dividends) December 31, 1988	Eventual minimum
Preferred $100 par value:					
3.40% Series; 200,000 shares	$ 20,000	$ 20,000	$ 20,000	$103.50	$103.50
3.60% Series; 350,000 shares	35,000	35,000	35,000	104.85	104.85
3.90% Series; 240,000 shares	24,000	24,000	24,000	106.00	106.00
4.10% Series; 210,000 shares	21,000	21,000	21,000	102.00	102.00
4.85% Series; 250,000 shares	25,000	25,000	25,000	102.00	102.00
5.25% Series; 200,000 shares	20,000	20,000	20,000	102.00	102.00
6.10% Series; 250,000 shares	25,000	25,000	25,000	101.00	101.00
7.72% Series; 400,000 shares	40,000	40,000	40,000	103.51	102.36
Preferred $25 par value:					
Adjustable Rate Series A; 1,200,000 shares	30,000	30,000	30,000	25.75	25.00
Adjustable Rate Series C; 2,000,000 shares	50,000	50,000	50,000	*(a)*	25.00
	$290,000	$290,000	$290,000		

(a) Not redeemable until 1990.

MANDATORILY REDEEMABLE PREFERRED STOCK

The Company has certain issues of preferred stock which provide for mandatory and optional redemption as follows:

At December 31,	In thousands of dollars 1988	1987	1986	Redemption price per share (Before adding accumulated dividends) December 31, 1988	Eventual minimum
Preferred $100 par value:					
7.45% Series; 384,000, 402,000, and 420,000 shares	$ 38,400	$ 40,200	$ 42,000	$103.85	$100.00
10.13% Series; none, 225,000 and 250,000 shares	—	22,500	25,000	—	—
10.60% Series; 160,000, 200,000 and 240,000 shares	16,000	20,000	24,000	107.95	102.65
12.75% Series; none and 250,000 shares	—	—	25,000	—	—
Preferred $25 par value:					
8.375% Series; 1,000,000, 1,100,000 and 1,200,000 shares	25,000	27,500	30,000	25.99	25.00
8.70% Series; 1,000,000 shares	25,000	25,000	—	*(a)*	25.00
8.75% Series; 3,000,000 shares	75,000	75,000	75,000	*(a)*	25.00
9.75% Series; 606,000, 672,000, and 738,000 shares	15,150	16,800	18,450	25.9075	25.00
9.75% Series (second); none and 816,000 shares	—	—	20,400	—	—
10.13% Series; none, 900,000 and 1,000,000 shares	—	22,500	25,000	—	—
10.75% Series; 1,600,000 shares	40,000	40,000	40,000	26.19	25.00
12.25% Series; 613,880, 656,940 and 700,000 shares	15,347	16,423	17,500	*(b)*	25.00
12.50% Series; 543,722, 581,861 and 620,000 shares	13,593	14,547	15,500	*(b)*	25.00
Adjustable Rate Series B; 2,000,000 shares	50,000	50,000	50,000	*(c)*	25.00
	313,490	370,470	407,850		
Less sinking fund and redemption requirements	17,980	14,980	60,380		
	$295,510	$355,490	$347,470		

(a) Not redeemable until 1992.
(b) Not redeemable until 1991.
(c) Not redeemable until 1989.

These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series and 300,000 shares of the 9.75% series). The option to redeem additional amounts is not cumulative.

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

	No. of shares	Commencing	1989	1990	1991	1992	1993
			In thousands of dollars				
Preferred $100 par value:							
7.45% Series	18,000	6/30/77	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800
10.60% Series	20,000	3/31/80	2,000	2,000	2,000	2,000	2,000
Preferred $25 par value:							
8.375% Series	100,000	4/1/83	2,500	2,500	2,500	2,500	2,500
8.70% Series	200,000	6/30/93	—	—	—	—	5,000
8.75% Series	600,000	12/31/92	—	—	—	15,000	15,000
9.75% Series	66,000	10/1/80	1,650	1,650	1,650	1,650	1,650
10.75% Series	320,000	6/30/89	8,000	8,000	8,000	8,000	8,000
12.25% Series	43,060	3/31/87	1,077	1,077	1,077	1,077	1,077
12.50% Series	38,139	3/31/87	953	953	953	953	953
Adjustable Rate Series B	50,000	9/30/93	—	—	—	—	1,250
			$17,980	$17,980	$17,980	$32,980	$39,230

LONG-TERM DEBT

Long-term debt and long-term debt due within one year consisted of the following:

At December 31,	1988	1987
	In thousands of dollars	
First mortgage bonds:		
3⅞% Series due June 1, 1988	$ —	$ 50,000
12% Series due March 1, 1989	20,000	20,000
* 9⅛% Series due October 1, 1989	13,000	13,000
4¾% Series due April 1, 1990	50,000	50,000
4½% Series due November 1, 1991	40,000	40,000
12.73% Series due February 1, 1992	20,000	20,000
13.06% Series due February 1, 1992	50,000	50,000
12.73% Series due February 20, 1992	10,000	10,000
12.68% Series due February 28, 1992	20,000	20,000
11% Series due May 1, 1993	50,000	50,000
8⅞% Series due August 1, 1994	150,000	150,000
4⅝% Series due December 1, 1994	40,000	40,000
9⅛% Series due October 1, 1996	100,000	100,000
5⅞% Series due November 1, 1996	45,000	45,000
9⅝% Series due July 1, 1997	100,000	100,000
6¼% Series due August 1, 1997	40,000	40,000
9⅞% Series due May 1, 1998	200,000	—
6½% Series due August 1, 1998	60,000	60,000
9⅛% Series due December 1, 1999	75,000	75,000
12.95% Series due October 1, 2000	48,002	58,668
7⅜% Series due February 1, 2001	65,000	65,000
7⅝% Series due February 1, 2002	80,000	80,000
7¾% Series due August 1, 2002	80,000	80,000
8¼% Series due December 1, 2003	80,000	80,000
9½% Series due December 1, 2003	44,118	47,059
9.95% Series due September 1, 2004	80,000	85,000
10.20% Series due March 1, 2005	30,478	31,578
8.35% Series due August 1, 2007	66,640	66,640
8⅝% Series due December 1, 2007	38,000	40,000
12⅞% Series due March 1, 2013	—	65,486
*11¼% Series due July 1, 2014	75,690	75,690
*11⅜% Series due October 1, 2014	40,015	40,015
10% Series due June 1, 2016	150,000	150,000
10% Series due November 1, 2016	100,000	100,000
* 8⅞% Series due November 1, 2025	75,000	75,000
Total First Mortgage Bonds	2,135,943	2,073,136
Promissory notes:		
* 8% Series A due June 1, 2004	46,600	46,600
*Adjustable Rate Series due		
July 1, 2015	100,000	100,000
December 1, 2023	69,800	—
December 1, 2025	75,000	75,000
December 1, 2026	50,000	50,000
March 1, 2027	25,760	25,760
July 1, 2027	93,200	93,200
Unsecured notes payable:		
Medium Term Notes, Various rates, due 1989-1994	200,000	200,000
Swiss Franc Bonds due December 15, 1995	50,000	50,000
15.02% Unsecured Notes due 1990	50,000	50,000
Notes, Interest Rate Exchange Agreement	75,000	50,000
Revolving credit agreement, Oswego Facilities Trust	—	36,259
Other	135,909	131,180
Unamortized premium (discount)	(893)	294
TOTAL LONG-TERM DEBT	3,106,319	2,981,429
Less long-term debt due within one year	110,571	77,508
	$2,995,748	$2,903,921

* Tax-exempt pollution control related issues

Several series of First Mortgage Bonds and Notes were issued to secure a like amount of tax-exempt revenue bonds and notes issued by the New York State Energy Research and Development Authority (NYSERDA). Approximately $414,000,000 of such securities bear interest at a daily adjustable interest rate (with a Company option to convert to a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 4.60% for 1988 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities.

Notes Payable include a ten-year Swiss franc bond issue equivalent to $50,000,000 in U.S. funds. Simultaneously with the sale of these bonds, the Company entered into a currency exchange agreement to fully hedge against currency exchange rate fluctuations.

The Company has Interest Rate Exchange Agreements extending into 1991 for $75,000,000. The agreements require the Company to make fixed rate payments which, calculated on a semi-annual bond basis, are equivalent to 7.53% and, in exchange, receive a LIBOR based floating rate payment from a bank. The Company generally uses its own commercial paper notes as the source of funding. The related interest expense is recorded on a net basis. Such Interest Rate Exchange Agreements include a $25,000,000 agreement previously held by the Oswego Facilities Trust (Trust). The Trust temporarily discontinued issuing commercial paper in July 1988 and the interest rate exchange agreement was transferred to the Company.

Other long-term debt in 1988 consists of obligations under capital leases of $65,854,000 (see Note 11) and a liability to the U.S. Department of Energy for nuclear fuel disposal of $70,055,000.

Certain of the Company's debt securities provide for a mandatory sinking fund for annual redemption. The Company's five-year mandatory sinking fund redemption requirements are as follows:

	Principal Amount	Commencing	1989	1990	1991	1992	1993
			In thousands of dollars				
First Mortgage Bonds:							
10.20% Series due March 1, 2005	$1,500	3/1/78	$ 1,478(a)	$ 1,500	$ 1,500	$ 1,500	$ 1,500
8.35% Series due August 1, 2007	750	8/1/82	(a)	(a)	(a)	(a)	640(a)
8⅝% Series due December 1, 2007	2,000	12/1/83	2,000	2,000	2,000	2,000	2,000
9.95% Series due September 1, 2004	5,000	9/1/85	5,000	5,000	5,000	5,000	5,000
12.95% Series due October 1, 2000	5,333	10/1/86	5,333	5,333	5,333	5,333	5,333
9½% Series due December 1, 2003	2,941	12/1/87	2,941	2,941	2,941	2,941	2,941
Promissory Notes:							
8% Series A due June 1, 2004	500	6/1/90	—	500	500	600	600
			$16,752	$17,274	$17,274	$17,374	$18,014

(a) Requirements, or a portion thereof, have been met by advance purchases.

Additionally, certain other series of mortgage bonds provide for a debt retirement fund whereby payment requirements may be met, in lieu of cash, by certification of additional property, the waiver of the issuance of additional bonds or the retirement of outstanding bonds. The 1988 requirements for these series were satisfied by the certification of additional property. The Company anticipates that the 1989 requirements for these series will be satisfied by other than payment in cash. Total annual debt retirement fund requirements for these series, based upon mortgage bonds outstanding December 31, 1988, are $6,550,000.

NOTE 8. Pension and Other Retirement Plans

The Company and its subsidiaries have non-contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on years of service and the employee's compensation level. The pension cost was $26,000,000 for 1988, $30,200,000 for 1987, $41,400,000 for 1986 (of which $7,800,000 for 1988, $11,400,000 for 1987 and $15,600,000 for 1986 was related to construction labor and, accordingly, was charged to construction projects). The Company's general policy is to fund the pension costs accrued with consideration given to the maximum amount that can be deducted for Federal income tax purposes. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

Net pension cost for 1988 and 1987 included the following components:

At December 31,	1988	1987
	In thousands of dollars	
Service cost—benefits earned during the period	$ 22,900	$ 26,900
Interest cost on projected benefit obligation	56,300	53,900
Return on Plan assets	(56,000)	(53,400)
Amortization of net obligation	2,800	2,800
Net pension cost	$ 26,000	$ 30,200

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care 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 while working for the Company. These benefits are provided through an insurance company whose premiums are based on the claims paid during the year. The cost of providing these benefits to retired employees amounted to approximately $12,600,000 for 1988, $8,800,000 for 1987 and $7,900,000 for 1986.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

At December 31,	1988	1987
	In thousands of dollars	
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$516,014	$493,625
Non-vested benefits	34,401	37,362
Accumulated benefit obligations	550,415	530,987
Additional amounts related to projected pay increases	194,405	201,415
Projected benefits obligation for service rendered to date	744,820	732,402
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	811,094	739,219
Plan assets in excess of projected benefit obligations	66,274	6,817
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	46,354	49,146
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	119,040	49,565
Prior service cost not yet recognized in net periodic pension cost	210	—
Prepaid (accrued) pension costs included in Other current assets and liabilities	$ (6,202)	$ 6,398

In 1988 and 1987, the discount rate and rate of increase in future compensation levels used in determining the actuarial present value of the projected benefit obligations were 8.25% and 4.5% (plus merit increases) and 8.0% and 5.0% (plus merit increases), respectively. The expected long-term rate of return on plan assets was 8.75% in 1988 and 8.0% in 1987.

NOTE 9. Federal and Foreign Income Taxes

Income Tax Reform: In October 1986, the Tax Reform Act of 1986 (Act) was signed into law. One of the provisions of the Act lowered the statutory corporate Federal income tax rate from 46% to 34% effective July 1, 1987. The deferred Federal income taxes below relating to book/tax timing differences have been provided at 34% in 1988, the blended statutory rate of approximately 40% for 1987 and at 46% in 1986.

Components of United States and foreign income before income taxes:

	In thousands of dollars 1988	1987	1986
United States	$322,814	$180,213	$570,113
Foreign	16,485	28,594	14,311
Consolidating eliminations	(9,621)	(23,571)	(7,615)
Income before income taxes and the cumulative effect of the accounting change in 1987	$329,678	$185,236	$576,809

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

Summary Analysis:	In thousands of dollars 1988	1987	1986
Components of Federal and foreign income taxes:			
Current tax expense: Federal	$ 60,173	$ 39,574	$ 24,959
Foreign	7,282	9,012	6,767
	67,455	48,586	31,726
Deferred Federal income tax expense	66,996	146,886	179,511
Income taxes included in Operating Expenses	134,451	195,472	211,237
Current Federal income tax expense included in Other Income and Deductions	—	—	13,475
Current Federal tax credits associated with disallowed plant depreciation	(29,068)	(19,070)	—
Deferred Federal income tax expense (credits) included in Other Income and Deductions	15,481	(48,952)	(45,768)
Total	$120,864	$127,450	$178,944
Components of deferred Federal income taxes *(Note 1):*			
Depreciation	$109,920	$ 96,812	$ 50,399
Investment tax credit	(392)	49,303	48,252
Alternative minimum tax	(33,786)	—	—
Benefit associated with disallowed plant costs	—	(50,400)	—
Construction overheads	(2,826)	14,492	26,111
Recoverable energy and purchased gas costs	8,664	(3,858)	(9,309)
Unbilled electric revenues	4,912	(15,181)	—
Gain on disposition of property	—	—	(15,374)
Reacquisition of bonds	(2,463)	3,299	15,700
Other	(1,552)	3,467	17,964
Deferred Federal income taxes (net)	$ 82,477	$ 97,934	$133,743
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	$112,091	$ 74,002	$265,332
Reduction attributable to flow-through of certain tax adjustments:			
Depreciation	(18,959)	(24,160)	(18,235)
Allowance for funds used during construction	3,747	12,336	76,266
Taxes, pensions and employee benefits capitalized for accounting purposes	3,929	(798)	1,645
Real estate taxes on an assessment date basis	2,537	859	4,074
Deferred taxes provided at other than the statutory rate	7,929	10,439	7,210
Tax adjustments associated with disallowed plant costs	—	(56,826)	—
Other	(7,956)	4,702	15,428
	(8,773)	(53,448)	86,388
Federal and foreign income taxes	$120,864	$127,450	$178,944

NOTE 10. Nuclear Operations

The Company is the owner and operator of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) and the operator and a 41% co-owner of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2) (See Note 5). Contingencies involving the Company's ownership of these facilities are discussed below.

Unit 1 Outage and Restart Action Plan: Unit 1 was taken out of service in December 1987 for repairs to its feedwater system. During these repairs, the Company decided to proceed from this outage into refueling of Unit 1, an activity that was previously scheduled to begin in March 1988. The Unit 1 outage was further extended to complete the in-service inspection required by the Nuclear Regulatory Commission (NRC) regulations. Such inspections are continuing. During March 1988, the NRC imposed a $100,000 civil penalty against the Company for failure to take corrective action and to comply with these NRC regulations relating to performing and evaluating the in-service inspections at Unit 1.

In April 1988, the Staff of the NRC (NRC Staff) completed a Systematic Appraisal of Licensee Performance (SALP) at Unit 1 covering the twenty-four month period ended February 1988. In this assessment, the NRC Staff identified certain areas in addition to the in-service inspection program which required increased management and NRC attention and expressed concern that these certain identified areas, if unattended, could give rise to significant performance problems.

During July 1988, the Company received a letter from the NRC Staff stating the Unit 1 was identified as having weaknesses that warrant increased NRC attention and require close monitoring. The NRC Staff contrasted certain weaknesses at Unit 1 with the satisfactory performance at Unit 2 (However, see "NRC Assessment of Nine Mile Point Station Performance" below). Citing the civil penalty relating to in-service inspections discussed above, the April 1988 SALP review and operator training and attitude concerns, the NRC Staff identified a trend that, in their view, is "of significant concern."

The NRC held a public meeting July 13, 1988 and, among other things, reviewed the performance of operating nuclear power plants licensed by the NRC. At this meeting, the NRC Staff indicated that Unit 1 would not be allowed to restart until such time as a comprehensive plan addressing and rectifying the NRC Staff's concerns is developed and approval for restart is received from the NRC Staff.

The Company developed a comprehensive plan to correct the root causes of the concerns raised by the NRC Staff and submitted this Restart Action Plan to the NRC Region I Administrator in December 1988. Restart of Unit 1 is conditioned upon the NRC Region I Administrator's concurrence that Unit 1 and management are ready to restart. Based upon a present assessment by the Company of the tasks to be completed prior to notification to the NRC of its readiness to restart, the Company anticipates that Unit 1 will not return to service prior to mid-1989. However, the Company can provide no assurance that the current scope of effort to be completed prior to notification of readiness to restart will not be expanded by future events of which the Company is not currently aware.

Interim Agreement on Unit 1 Outage Replacement Power Costs: On May 23, 1988, the Attorney General of the State of New York filed a petition with the PSC requesting that the PSC, 1) cease recovery of replacement power costs incurred by the Company as a result of the Unit 1 outage discussed above, 2) institute a proceeding to determine whether the Company should refund replacement power costs already collected and 3) remove Unit 1 from the Company's rate base until Unit 1 returns to service. In an order issued September 8, 1988, the PSC instituted a proceeding, based upon its authority to order the refund of any imprudently incurred costs, to investigate the Unit 1 outage. The further relief sought by the Attorney General was denied subject to the possibility of being reconsidered at a later date.

The Company, the PSC Staff, the Attorney General, the Consumer Protection Board and Multiple Intervenors reached an interim relief agreement (the "Interim Relief Agreement"), which was approved by the PSC in an order issued January 26, 1989. The Interim Relief Agreement provides that the Company, commencing with the fuel cost month of January 1989 until the earlier of restart of Unit 1 or June 30, 1989, will temporarily suspend collection from ratepayers of $225 thousand per day through the fuel adjustment clause mechanism, which approximates the incremental replacement power costs relating to the outage which would otherwise be funded by ratepayers. This will reduce the Company's cash flow during the period by approximately $6.75 million per month.

The Company will defer such amounts for regulatory purposes, with appropriate carrying charges, for future recovery pending the results of the PSC's prudence investigation. However, the degree of uncertainty associated with the ultimate outcome of the PSC's prudence investigation will preclude the accrual of these revenues for financial reporting purposes, which will have the result of reducing earnings per share during the period by approximately $.03 per month. The Company will also continue to absorb its share of the replacement power costs as provided for in the fuel adjustment clause mechanism and the incremental operating expenses incurred during the outage not provided for in rates. The replacement power cost associated with the Unit 1 outage is approximately $250 to $300 thousand per day, the precise amount of which is dependent upon seasonal factors and relative demand.

These amounts do not include additional expenses associated with preparing for the restart of Unit 1 and complying with NRC requirements relating to the Company's management of operations at its nuclear facilities. (see "Results of Operations" in Management's Discussion and Analysis)

The Interim Relief Agreement obviated the need for the Company to litigate at this time the question of the appropriateness of interim rate relief and thus permits continued concentration of the Company's resources on the effort to restart Unit 1. The Interim Relief Agreement does not resolve any issues of responsibility which may arise during the conduct of the prudence investigation and is not an admission of imprudence by the Company. If Unit 1 is not returned to service by June 30, 1989, the parties to the Interim Relief Agreement will be free to seek an extension of interim relief in whatever form they think appropriate. The Company cannot predict what form an extension of interim relief might take, if sought, or the resultant impact on the Company's financial condition or results of operations. (see"Results of Operations" in Management's Discussion and Analysis)

Through December 31, 1988, the Company has collected from ratepayers approximately $75.9 million of increased fuel adjustment clause revenues occasioned by the Unit 1 outage. These revenues are subject to full or partial refund if the Company is found to have acted imprudently in a way which caused or extended the outage. The Company is unable to predict the results of the PSC's prudence investigation, what sanctions may ultimately be imposed and the impact on the Company's financial condition, results of operations or level of retained earnings which might result if any such sanctions are imposed.

Unit 2 Mid-cycle Outage: On October 1, 1988, Unit 2 began a scheduled maintenance and inspection mid-cycle outage which was expected to be completed by the end of December 1988. The outage has been extended to March 1989 to effect repair and retest of a main steam isolation valve, repair of generator retaining rings, replacement of a generator coupling, repair and retest of six valves in the residual heat removal system and conduct required surveillance tests.

NRC Assessment of Nine Mile Point Station Performance: In December 1988, NRC senior managers conducted their biannual review of the performance of nuclear power plants licensed by the NRC. As a result of this review, the Company was advised on December 20, 1988, that the Nine Mile Point Station (Units 1 and 2) was being categorized as requiring close monitoring by the NRC. The conclusion was based on current NRC assessment of Unit 2's overall performance in certain areas during the first year of its operation and a June 1988 assessment of the overall performance of Unit 1 (See Unit 1 Outage and Restart Action Plan above). Further, the NRC Staff observed that increased licensee and NRC management attention is needed to ensure that performance improvement at the Nine Mile Point Station is achieved. A public meeting of the NRC was held on December 21, 1988, wherein the need for increased licensee and NRC management attention was confirmed.

Unit 2 Ratemaking and Cost Settlement: In September 1986, the PSC approved an agreement entitled "Specifications of Terms and Conditions of Offer of Settlement" (the Settlement) that constitutes a complete disposition of a July 1985 PSC proceeding established to investigate the prudence of costs incurred for the construction of Unit 2. The Settlement contains, among other stipulations, key terms and conditions which provide that the maximum amount of Unit 2's construction expenditures to be included in the cotenants' rate bases would be $4.16 billion and that each cotenant would waive any and all claims it may have against any other cotenant concerning the design, engineering or construction of Unit 2.

In order to induce concurrence among the cotenants while the Settlement was being negotiated, the Company entered into an agreement with the other cotenant companies (Cotenant Agreement) whereby it reimbursed the cotenant companies, upon commercial operation of Unit 2 as ultimately recognized by the PSC, for $171 million representing the cotenants' share of the $290 million difference between the Settlement's originally proposed allowed cost of $4.450 billion and the approved settlement value of $4.160 billion. Payment to the cotenants did not cause a reallocation of ownership interests in Unit 2.

In connection with the Company's rate case decided in March 1987, the PSC adopted their Staff's position on Settlement implementation issues, which included, for ratesetting purposes, the recognition of tax benefits at primarily a 34% rate rather than preservation at a 46% rate, the recording of deferred Federal income tax benefits in present value dollars, exclusion from rate base of unrealized tax benefits, the disallowance of certain plant-related costs, such as common facilities, and a write-off of disallowed costs, net of Federal income taxes, entirely against common equity. These requirements have had a detrimental impact on the financial condition and results of operations of the Company. The Company believes that the implementation requirements ordered by the PSC are contrary to the terms and intent of the Settlement and, in July 1987, the Company and Cotenant companies appealed the PSC's decision to the State of New York Supreme Court—Albany County. The Company is unable to predict the results of such action.

Several intervening parties petitioned the PSC for rehearing of its decision in connection with the Settlement and such petitions were denied. In April 1987, the Consumer Protection Board and the Attorney General of the State of New York filed a lawsuit asking that the PSC decision be annulled and that the PSC be directed to conduct a full prudence investigation with respect to Unit 2. The Company is unable to predict the ultimate outcome of this proceeding.

Based upon the Settlement as implemented by the PSC, the commercial operation date of April 5, 1988 as provided for in the Stipulation Agreement (see discussion in Management's Discussion and Analysis of Financial Condition and Results of Operations), the $171 million payment to the cotenants and the disallowance of certain plant related costs, approximately $1,147 million of the Company's share of project costs will not be recoverable in rates. See "Unit 2 Financial Accounting Recognition" below.

Unit 2 Financial Accounting Recognition: In December 1986, the FASB issued Statement of Financial Accounting Standards No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs," an amendment of FASB Statement No. 71 (SFAS No. 90). Among other things, SFAS No. 90 requires that when it becomes probable that part of the cost of a generating facility will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss.

The Company adopted SFAS No. 90 in 1987 and recognized as a loss for financial accounting purposes the disallowance of Unit 2 costs, including the cost of disallowed plant related facilities, of approximately $1,147 million, reduced to $833 million ($6.54 per share) net of Federal income taxes. The ultimate amount of the disallowance is dependent upon a final determination of the cost of Unit 2 and subsequent approval by the PSC.

Pursuant to the Stipulation Agreement entered into by the Company and other parties and approved by the PSC, a separate, non-rate case proceeding was established to litigate remaining Unit 2 settlement cap issues. The proceeding is to begin following the conclusion of the current mid-cycle outage. The Company is unable to predict the outcome of the proceeding or the resultant impact on its financial condition or results of operation.

Unit 2 Contractor Litigation: In connection with problems encountered with Unit 2's original Main Steam Isolation Valves (MSIV's), which caused a major delay in the completion of Unit 2, the Company and the cotenant companies have initiated a lawsuit in New York State Supreme Court in Syracuse, New York, seeking damages of approximately $500 million against Gulf + Western, Inc., Crosby Valve and Gage Company and Wickes Manufacturing Company, the companies having contractual responsibility for the design and fabrication of Unit 2's original MSIV's. The defendants have filed their answer which disagrees with the Company's claim. The Company is unable to predict the ultimate outcome of the lawsuit.

On August 1, 1988, the Company and the cotenant companies initiated a lawsuit in federal court in Syracuse, New York, against three corporations involved in the construction of Unit 2, Stone & Webster Engineering Corp. (the architect-engineer and construction manager for Unit 2), ITT Fluid Products Corp. and ITT Fluid Technology Corp. (successor companies to ITT Grinnell, a major piping contractor of Unit 2). The lawsuit seeks damages for, among other things, breach of contractual and professional obligations in their performance under their contracts which resulted in delays and cost overruns. Stone & Webster Engineering Corporation has filed its answer which disagrees with the Company's claim. Filing of answers by the other two defendants has been delayed pending resolution of their motion to dismiss portions of the complaint. The Company is unable to predict the ultimate outcome of the lawsuit.

In connection with the Unit 2 contractor litigation discussed above, the Company must submit its proposed accounting for any settlement proceeds received to the PSC for approval.

The Company and cotenant companies have entered into an agreement with General Electric Company (GE) relating to certain disputes which arose in connection with the Nuclear Steam Supply System (NSSS) portion of the construction of Unit 2, providing for settlement, mutual releases, and confidentiality of the specific elements of the agreement. The agreement provides that GE will supply certain goods and services to the Company and cotenant companies over a period of years without cost or at a reduced cost. Among other things, GE will supply engineering services which will improve Unit 2's technical specifications and which may ultimately result in the increased capacity of Unit 2; software designed to help avoid unplanned outages; other goods and services in support of Unit 2; and other goods and services relating to turbine upgrading and maintenance at the Company's and cotentant companies' generating facilities.

GE will receive indemnification, including limited reimbursement of legal expenses, from the Company and cotenant companies against any future judgments against GE brought by other Unit 2 contractors related to the NSSS portion of the construction of Unit 2, to the extent such judgments result from successful Company and cotenant company claims against the contractors.

While the Company does not believe that current treatment of the agreement is material to its financial position, the Company regards this as a favorable settlement. No part of the Agreement has been included in income pending determination by the PSC of the allocation of the benefits thereof between the Company's shareholders and its ratepayers.

Nuclear Plant Decommissioning: Based on a study completed in 1986, the cost of decommissioning Unit 1, which is expected to begin in the year 2005, is estimated by the Company to be approximately $442,000,000 at that time ($229,000,000 in 1988 dollars). The Company's 41% share of costs to decommission Unit 2, which is expected to begin in the year 2027, is estimated by the Company to be approximately $565,000,000 ($116,900,000 in 1988 dollars). The current annual allowances for recovery are based on total estimated decommissioning costs over the life of these units as previously authorized in rates, which amount to $195,300,000 and $256,400,000 (in future dollars), respectively, to be available in the year of decommissioning. Through December 31, 1988, the Company has recovered $31,200,000 of decommissioning costs in rates for both units. The Company continues to review the estimated requirements for decommissioning and plans to seek rate adjustments when appropriate. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that decommissioning costs, if higher than currently estimated, will ultimately be recovered in the rate process, although no such assurance can be given.

The NRC has recently issued regulations requiring owners of nuclear power plants to place costs associated with specific decommissioning activities into an external trust at a substantially accelerated rate from what has heretofore been required. Further, the NRC established guidelines for determining minimum amounts that must be available in the trust for these specified decommissioning activities at the time of decommissioning. The Company anticipates that the NRC minimum will exceed the basis of current cost recovery for total decommissioning costs associated with the Units. As a result, the NRC regulations, which have not been considered in the rate setting environment, could require the Company to increase its capital requirements by an amount which cannot currently be determined. The Company has until July 1990 to file a decommissioning plan for each unit with the NRC.

Nuclear Liability Insurance: In August 1988, amendments were enacted to the Price-Anderson Act (the Act) which significantly increase liability limits under the Act and extend its effectiveness to the year 2002. The public liability limit with respect to a nuclear accident at a licensed reactor increased from $710 million to approximately $7.1 billion, with the excess over commercially available insurance to be funded by assessments of up to $63 million per licensed facility for each nuclear incident, payable at a rate not to exceed $10 million per year. Such assessments are subject to periodic inflation-indexing and to a 5% surcharge if funds prove insufficient to pay claims. The Company's interest in Units 1 and 2 could expose it to a potential loss, for each accident, of $88.8 million through assessments of $14.1 million per year in the event of a sufficiently serious nuclear accident at its own or another U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations whether or not a nuclear incident actually occurs.

NOTE 11. Commitments and Contingencies

Construction Program: The Company is committed to an ongoing construction program to assure reliable delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1989 through 1993 will require approximately $1.5 billion, excluding AFC, nuclear fuel and certain overheads capitalized. For the years 1989 through 1993, the estimates are $307 million, $298 million, $283 million, $317 million and $294 million, respectively.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1989, the Company had long-term contracts to purchase electric power from the following generating facilities owned by the New York Power Authority (NYPA):

Facility	Expiration date of contract	Purchased capacity in kw.	Estimated annual capacity cost
Niagara—hydroelectric project ..	1990	1,077,000	$14,515,000
Blenheim-Gilboa—pumped storage generating station	2002	295,000	6,346,000
FitzPatrick—nuclear plant	year-to-year basis	53,000 (a)	5,735,000
		1,425,000	$26,596,000

(a) 21,000 kw for summer of 1989; 45,000 kw. for winter of 1989-90.

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. Total cost of purchases under these contracts amounted to $46.3 million, $57.2 million and $68.5 million for the years 1988, 1987 and 1986, respectively. The Company and NYPA have reached an agreement in principle to extend the Niagara project contract into 2007. This extension is currently in the approval process.

Under the requirements of the Federal Public Utility Regulatory Policy Act, the Company is required to purchase power generated by Qualifying Facilities as defined therein. Approximately $95 million was paid to Qualifying Facilities in 1988 for 1,497,000,000 kwh of energy and associated capacity. Through December 31, 1988, the Company has entered into agreements with numerous current and prospective independent producers, including Qualifying Facilities, which may substantially increase its future purchase power commitments.

Lease Commitments: The Company leases certain property and equipment which meet the accounting criteria for capitalization. Such leases, having a net book value of $65.9 million and $65.6 million at December 31, 1988 and 1987, respectively, are included in the accompanying Consolidated Balance Sheets. Since current rate-making practice treats all leases as operating leases, the capitalization of these leases has no impact on the Company's Consolidated Statements of Income. The Company recognizes as a charge against income an amount equal to the rental expense allowed for rate purposes. The Company's future minimum rental commitments under these capital leases and non-cancellable operating leases aggregate approximately $650 million, a substantial portion of which relates to a 41-year lease of a transmission line facility. Annual future minimum rental commitments for the period 1989-1993 range between $24 million and $33 million.

Sale of Customer Receivables: During 1988, the Company entered into an agreement whereby it can sell an undivided interest in a designated pool of customer receivables up to a maximum of $100,000,000. At December 31, 1988, $100,000,000 of receivables were sold under this agreement. The undivided interest in the designated pool of receivables was sold with limited recourse. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser.

Litigation: The Board of Trustees of the Town of Brookhaven (Long Island) instituted a lawsuit on March 3, 1987 against the Company, the General Electric Company and Monsanto Company in the United States District Court for the Eastern District of New York alleging damages in the amount of $300,000,000 as a result of the disposal of polychlorinated biphenyls (PCB's) in the Hudson River which is alleged to have impacted the striped bass and other commercial fisheries off of eastern Long Island. A further allegation in the complaint against the Company is that the removal of its Fort Edward Dam, located in the Hudson River, in the Village of Fort Edward, Washington County, New York, caused PCB's which had previously been impounded thereby to be transported downstream to the detriment of such fisheries. Since fishing restrictions off of eastern Long Island have been relaxed, the plaintiffs have discontinued the lawsuit with prejudice.

In May 1988, a stockholders' derivative suit was commenced in the United States District Court, Northern District of New York, against certain members of the Board of Directors and several officers of the Company. The complaint purported to state claims on behalf of the Company for alleged violations of the federal securities laws and state law in connection with the Nine Mile Point Unit No. 2 project. The defendants filed a motion to dismiss the action. The plaintiffs opposed the motion but also filed an amended complaint adding new counts and a new party plaintiff. In October, the Court granted the defendants' motion to dismiss the original complaint. At the same time, the Court permitted plaintiffs the opportunity to file a second amended complaint, with certain restrictions concerning the scope of their federal securities law claim.

On January 17, 1989, the plaintiffs filed a second amended complaint. As in the first amended complaint, the new complaint purports to state a claim on behalf of the Company for alleged violations of the federal securities laws and for alleged negligence, mismanagement, waste and breaches of fiduciary duty, all in connection with the Nine Mile Point Unit 2 project. The amount of damage claimed is not specified. The defendants intend to contest this suit vigorously.

As permitted by law and by its by-laws, the Company has indemnified its officers and directors for loss and expense, including judgments or settlements, incurred in connection with the defense of such actions, and has directors and officers liability insurance to cover all or part of its indemnification obligation.

The Company is unable to predict the ultimate outcome of the action.

Guarantee of Nine Mile Point Nuclear Unit No. 2 Cotenant's Debt: Under the terms of an agreement (Capital Funds Agreement) with Long Island Lighting Company (LILCO), the Company provided its guarantee in December 1985 for a period of approximately three years through March 16, 1989 of up to $165 million of LILCO's reimbursement obligations in connection with $150 million principal amount of tax-exempt pollution control bonds issued on behalf of LILCO on December 31, 1985. On February 3, 1989 the Company consented to an extension of the tax-exempt arrangement for approximately two years through March 1991. LILCO is required to pay certain fees to the Company in connection with the guarantee. If and to the extent LILCO does not honor its obligations to the banks, the Company would be required to do so and has arranged for three-year term loans to fund its guarantee obligations. Upon payment of the LILCO obligation, the Company would become the holder of LILCO's debt, which would bear interest at 16%. The Company has an interest of $85 million in LILCO's third mortgage, which serves as partial security in the event its guarantee is required to be honored. However, in the event of a LILCO bankruptcy, the Company can provide no assurance as to its ability to realize the full value of its third mortgage interest. If the Company's First Mortgage Bond credit rating is below investment grade and the Company owes amounts to the banks under its three-year term loan, the banks have the right to require the Company to issue First Mortgage Bonds as security.

Securities and Exchange Commission filings of LILCO indicate that LILCO continues to face severe financial and legal difficulties and may be forced to seek relief in bankruptcy. LILCO's auditors qualified their opinion on the 1987 financial statements, questioning LILCO's ability to remain financially viable.

During December 1988, the proposed Settlement involving LILCO's Shoreham Plant failed to gain ratification by the New York legislature. Although efforts to revive the Settlement in some form continue, the form any ultimate Settlement may take, if achieved, cannot currently be determined. In addition, Suffolk County obtained a jury verdict against LILCO in December 1988 for $23 million in connection with claimed perjury by LILCO which allegedly resulted in certain rate increases being awarded to LILCO by the New York Public Service Commission. Motions in Federal Court to certify the action as a class action, to overturn the verdict and on other related matters were heard on February 2, 1989, with no action taken. The judge in the case has stated that LILCO's potential liability in connection with a class action on the issue could exceed $4 billion, which is substantially in excess of LILCO's stockholders' equity. The above factors could adversely impact the contractual obligations of the Company with respect to LILCO and LILCO to the Company and have substantially reduced or eliminated the possibility of a substitute guarantor being obtained by LILCO under the current arrangement. The Company will continue to monitor the LILCO situation with a view to best protecting the Company's financial interest.

NOTE 12. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income and earnings per common share by quarters for 1988, 1987 and 1986 are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The proforma amounts for Net Income (loss) and Earnings per common share presented in the table below reflect the retroactive application for SFAS No. 90 for comparative purposes.

	In thousands of dollars				*Proforma Amounts*	
Quarter ended	Operating revenues	Operating income	Net income (loss)	Earnings per common share	Net income (loss)	Earnings per common share
Dec. 31, 1988	$678,858	$ 68,245	$ (3,808)	$(.12)	$ —	$ —
1987	653,906	114,509	(32,649)*	(.36)*	(32,649)	(.36)
1986	637,896	104,633	84,698	.57	(4,302)	(.13)
Sept. 30, 1988	$608,393	$115,691	$ 52,297	$ .31	$ —	$ —
1987	556,845	98,958	44,829	.25	44,829	.25
1986	554,546	92,640	74,909	.49	33,909	.17
June 30, 1988	$702,678	$128,008	$ 46,823	$ .27	$ —	$ —
1987	624,628	102,810	48,711	.29	48,711	.29
1986	636,859	97,585	85,535	.56	(100,465)	(.90)
March 31, 1988	$810,524	$170,221	$113,502	$ .77	$ —	$ —
1987	788,051	169,121	(618,105)*	(4.96)*	(3,105)	(.13)
1986	831,018	146,316	152,723	1.08	140,723	.99

*See Note 10 regarding first and fourth quarter 1987 adjustments relating to the adoption of SFAS No. 90.

Year end adjustments to annual estimates of taxes and expense accruals made in the fourth quarter of 1988 had the effect of decreasing net income for the quarter by approximately $14 million or $.11 per common share. In addition, in the fourth quarter of 1988 and 1987 the Company accrued $7.5 million ($.04 per common share) and $13.0 million ($.08 per common share), respectively, relating to its investment in NM Uranium, Inc., resulting in a decrease in net income for each quarter (see Note 3).

Report of Management

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

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Code of Conduct which requires all employees to maintain the highest level of ethical standards and requires key management employees to formally affirm their compliance with the Code.

The financial statements have been examined by Price Waterhouse, the Company's independent accountants, in accordance with generally accepted auditing standards. As part of their examination, they made a study and evaluation of the Company's system of internal accounting control. The purpose of such study was to establish a basis for reliance thereon in determining the nature, timing and extent of other auditing procedures that were necessary for expressing an opinion as to whether the financial statements are presented fairly in all material respects. Their examination resulted in the expression of their opinion which follows this report. The independent accountants' examination does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report.

The Audit Committee of the Board of Directors, consisting of four directors who are not employees, meets regularly with management, internal auditors and Price Waterhouse to review and discuss internal accounting controls, audit examinations and financial reporting matters. Price Waterhouse and the Company's internal auditors have free access to meet individually with the Audit Committee at any time, without management present.

Report of Independent Accountants

Price Waterhouse

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1988 and 1987, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1988, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As described in Note 10, the Company adopted in 1987 Statement of Financial Accounting Standards No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs." The adoption of this Statement resulted in the disallowed portion of the Company's investment in the Nine Mile Point Nuclear Station No. 2 (Unit 2) being recognized as a loss in the 1987 financial statements.

As a result of continuing uncertainties with respect to Unit 2 discussed in Note 10, management is unable to predict whether further regulatory actions by the New York State Public Service Commission (PSC) with respect to its investment in the Unit will have, in the aggregate, a material effect on its financial position or results of operations. Accordingly, no provision for any additional loss that may result upon resolution of these uncertainties has been made in the accompanying financial statements.

As discussed in Note 10, in 1988 the PSC instituted a proceeding, based upon its authority to order the refund of any imprudently incurred costs, to investigate the Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) outage. Management is unable to predict whether further regulatory actions by the PSC related to the Unit 1 outage will have a material effect on its financial position or results of operations. Accordingly, no provision for loss that may result upon resolution of this uncertainty has been made in the accompanying 1988 financial statements.

Price Waterhouse

Syracuse, New York
January 26, 1989

Selected Financial Data

As discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to Consolidated Financial Statements, certain of the following selected financial data may not be indicative of the Company's future financial condition or results of operations. Certain of 1987 data is not presented since it is either not meaningful or not applicable in light of the adoption of SFAS No. 90 which required the write-off of disallowed Unit 2 costs and resulted in a net loss for the year.

	1988	1987	1986	1985	1984
Operations: *(000's)*					
Operating revenues	$2,800,453	$2,623,430	$2,660,319	$2,694,940	$2,785,546
Income before cumulative effect of accounting change	208,814	57,786	397,865	411,430	359,734
Cumulative effect on prior years of adoption of SFAS No. 90	—	(615,000)	—	—	—
Net income (loss)	208,814	(557,214)	397,865	411,430	359,734
Proforma balance available for common stock —giving effect to the retroactive application of SFAS No. 90	—	5,769	16,048	64,871	359,734
Common stock data:					
Book value per share at year end	$ 13.87	$13.82	$20.23	$19.61	$18.89
Market price at year end	13	12	16¾	20½	17⅜
Ratio of market price to book value at year end	93.7%	86.8%	82.8%	104.5%	92.0%
Dividend yield at year end	9.2%	10.0%	12.4%	10.1%	11.5%
Earnings per average common share before cumulative effect of accounting change	$ 1.21	$ .05	$ 2.71	$ 2.88	$ 2.84
Cumulative effect on prior years of adoption of SFAS No. 90 per average common share	—	(4.83)	—	—	—
Earnings per average common share	1.21	(4.78)	2.71	2.88	2.84
Proforma earnings per average common share —giving effect to the retroactive application of SFAS No. 90	—	.05	.13	.53	2.84
Rate of return on common equity	8.7%	12.7%*	13.6%	15.0%	14.9%
Dividends paid per common share	$ 1.20	$ 1.64	$ 2.08	$ 2.06	$ 1.98
Dividend payout ratio	99.2%	—	76.8%	71.5%	69.7%
Capitalization: *(000's)*					
Common equity	$1,881,394	$1,781,518	$2,571,491	$2,488,620	$2,207,117
Non-redeemable preferred stock	290,000	290,000	290,000	290,000	240,000
Redeemable preferred stock	295,510	355,490	347,470	379,850	367,900
Long-term debt	2,995,748	2,903,921	2,799,605	2,643,094	2,395,471
Total	5,462,652	5,330,929	6,008,566	5,801,564	5,210,488
First mortgage bonds maturing within one year	33,000	50,000	50,000	30,000	47,450
Total	$5,495,652	$5,380,929	$6,058,566	$5,831,564	$5,257,938
Capitalization ratios: *(including first mortgage bonds maturing within one year):*					
Common stock equity	34.2%	33.1%	42.5%	42.7%	42.0%
Preferred stock	10.7	12.0	10.5	11.5	11.5
Long-term debt	55.1	54.9	47.0	45.8	46.5
Financial ratios:					
Ratio of earnings to fixed charges	2.10	1.65**	2.98	3.07	3.11
Ratio of earnings to fixed charges without AFC	2.06	1.54**	2.42	2.37	2.43
Ratio of AFC to balance available for common stock	6.9%	-	48.2%	53.2%	52.4%
Ratio of earnings to fixed charges and preferred stock dividends	1.67	1.04**	2.35	2.36	2.39
Proforma Ratios—giving effect to the retroactive application of SFAS No. 90:					
Earnings to fixed charges	—	1.65	1.28	1.40	3.11
Earnings to fixed charges and preferred stock dividends	—	1.04	1.05	1.17	2.39
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	34.6%	35.6%	38.0%	43.4%	46.9%
Maintenance, depreciation and amortization	15.1	12.1	11.4	10.9	10.1
Total taxes	16.1	16.7	18.1	15.7	14.7
Operating income	17.2	18.5	16.6	15.3	14.1
Balance available for common stock	5.7	—	12.9	13.1	11.1
Miscellaneous: *(000's)*					
Gross additions to utility plant	$ 353,859	$ 447,230	$ 774,062	$ 771,120	$ 769,846
Total utility plant	7,967,625	7,691,069	8,445,993	7,640,905	6,903,184
Accumulated depreciation and amortization	2,090,170	1,913,687	1,763,443	1,629,437	1,501,282
Total assets	7,076,041	6,794,098	7,611,203	7,013,837	6,233,401

*Excludes the effect of the adoption of SFAS No. 90 amounting to $833 million.

**Excudes the cumulative effect of the adoption of SFAS No. 90 amounting to $615 million.

Directors

William F. Allyn *(E,F)*
President & Chief Executive Officer Welch Allyn, Inc., Skaneateles Falls

James Bartlett *(Retired May 2, 1988)*
Former Executive Vice President, Syracuse

Lawrence Burkhardt, III *(F) (Elected October 24, 1988)*
Executive Vice President, Nuclear Operations

Edmund M. Davis *(A, B, E,)*
Partner, Hiscock & Barclay, attorneys-at-law, Syracuse

William J. Donlon *(A)*
Chairman of the Board and Chief Executive Officer

Edward W. Duffy *(A, B, C, F)*
Former Chairman of the Board and Chief Executive Officer, Marine Midland Banks, Inc. a bank holding company, Buffalo

John M. Endries
President

John G. Haehl, Jr.
Former Chairman of the Board and Chief Executive Officer

Lauman Martin *(Retired May 2, 1988; Died June 2, 1988)*
Consultant (formerly Senior Vice President and General Counsel), Syracuse

Baldwin Maull *(A, B)*
Corporate Director, New York

Martha Hancock Northrup *(C, D)*
Homemaker, former President, Crouse-Irving Memorial Hospital Board, Syracuse

Henry A. Panasci, Jr. *(B, E)*
Chairman of the Board and Chief Executive Officer, Fay's Drug Company, Inc., Liverpool

Patti McGill Peterson *(C, D)*
President, St. Lawrence University, Canton

Frank P. Piskor *(A, C, F)*
President Emeritus, St. Lawrence University, Canton

Donald B. Riefler *(E, F)*
Chairman, Market Risk Committee, Morgan Guaranty Trust Company of New York, New York

Steven Browning Sample *(D, F)*
President, State University of New York at Buffalo, Buffalo

Lewis A. Swyer *(Died December 25, 1988)*
Chairman, L.A. Swyer Co., Inc., builders and construction managers, Albany

John G. Wick *(D, E)*
Partner, Falk & Siemer, attorneys-at-law, Buffalo

A. Member of the Executive Committee
B. Member of the Compensation Committee
C. Member of the Audit Committee
D. Member of the Committee on Corporate Public Policy
E. Member of the Finance Committee
F. Member of the Nuclear Oversight Committee

Officers

William J. Donlon
Chairman of the Board and Chief Executive Officer
(Elected June 1, 1988)

John M. Endries
President
(Elected June 1, 1988)

Lawrence Burkhardt, III
Executive Vice President, Nuclear Operations

Anthony J. Baratta, Jr.
Senior Vice President

John P. Hennessey
Senior Vice President

Charles V. Mangan
Senior Vice President

John W. Powers
Senior Vice President and Treasurer

Michael P. Ranalli
Senior Vice President

Joseph T. Ash
Vice President, Consumer Services

Thomas H. Baron
Vice President, Fossil Generation

Michael J. Cahill
Vice President, Regional Operations

Robert M. Cleary, Jr.
Vice President, Regional Operations

Richard E. A. Duffy
Vice President, Public Affairs & Corporate Communications

Gerald D. Garcy
Vice President, Power Contracts

James P. Gorman
Vice President, Corporate Audits

Edward F. Hoffman
Vice President, Engineering (Non-Nuclear)

Darlene D. Kerr
Vice President, System Electric Operations

Gary J. Lavine
Vice President, General Counsel and Secretary

Samuel F. Manno
Vice President, Purchasing & Materials Management

Thomas J. Perkins
Vice President, Nuclear
(Died November 24, 1988)

James A. Perry
Vice President, Quality Assurance

Nicholas L. Prioletti, Jr.
Controller

Richard H. Ryczek
Vice President, Gas

Jack R. Swartz
Vice President, Regional Operations

Carl D. Terry
Vice President, Nuclear Engineering and Licensing

Perry B. Woods, Jr.
Vice President, Human Resources

Harold J. Bogan
Assistant Secretary

Joseph F. Cleary
Assistant Secretary

John J. Hennigan
Assistant Secretary

John W. Keib
Assistant General Counsel

Frederick C. McCall, Jr.
Assistant Secretary

Arthur W. Roos
Assistant Treasurer

Robert A. Sanguine
Assistant Controller

Steven W. Tasker
Assistant Controller

Ronald A. Ungerer
Assistant Controller

Richard N. Wescott
Assistant Treasurer

Henry B. Wightman, Jr.
Assistant Controller, Nuclear

Corporate Information

Annual Meeting

The annual meeting of shareholders will be held in the auditorium of the Everson Museum of Art, 401 Harrison Street, Syracuse, N.Y. 13202 at 10:30 a.m. Tuesday, May 2, 1989. A notice of the meeting, proxy statement and form of proxy will be sent to holders of common stock in early April.

Shareholder Inquiries

Questions regarding ownership of Niagara Mohawk stock or the status of an account may be directed to the Company's Shareholder Services Department,
(315) 428-6750 (Syracuse)
1-800-962-3236 (New York State)
1-800-448-5450 (elsewhere in continental U.S.)

Analyst Inquiries
Analyst inquiries should be directed to Leon T. Mazur, Manager-Investor Relations, (315) 428-3134.

Dividend Reinvestment Plan

Shareholders and customers interested in purchasing common stock through the Dividend Reinvestment and Common Stock Purchase Plan should call or write our Shareholder Services Department at P.O. Box 7058, Syracuse, N.Y. 13261.

SEC Form 10-K Report

A copy of the Company's Form 10-K Report filed annually with the Securities and Exchange Commission is available without charge after March 31, 1989, by writing the Investor Relations Department at 300 Erie Boulevard West, Syracuse, N.Y. 13202.

Disbursing Agent

Preferred and Common Stocks:
Niagara Mohawk Power Corporation
300 Erie Boulevard West, Syracuse, N.Y. 13202
Bonds:
Marine Midland Bank, N.A.
140 Broadway, New York, N.Y. 10015

Transfer Agents and Registrars

Preferred and Common Stocks:
Morgan Shareholder Services Trust Company of New York
30 West Broadway, New York, N.Y. 10015
Bonds:
Marine Midland Bank, N.A.
140 Broadway, New York, N.Y. 10015

Stock Exchanges

Common Stock and Certain Preferred Series:
Listed and traded on the New York Stock Exhange.

Common Stock: Also traded on the Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges.

Bonds: Traded on the New York Stock Exchange.

Ticker Symbol: NMK

Corporate Headquarters
300 Erie Boulevard West
Syracuse, New York 13202
(315) 474-1511

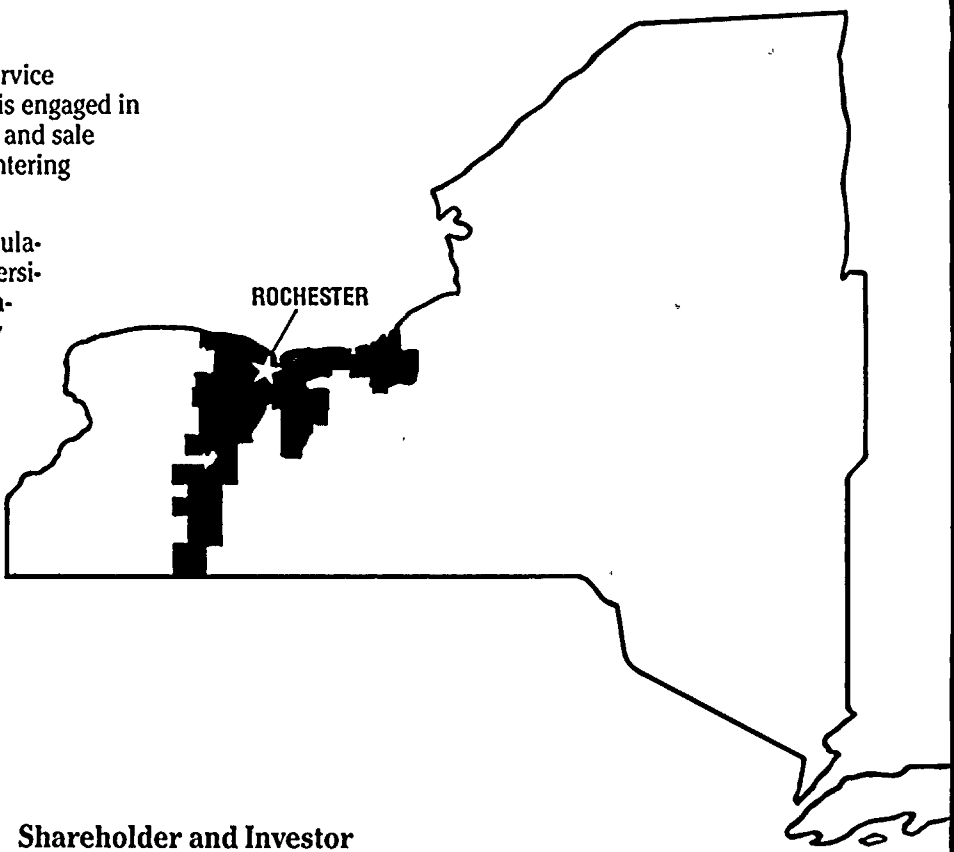
ROCHESTER GAS and ELECTRIC CORPORATION

1988 ANNUAL REPORT

RG&E Service Area/Business

The Company supplies electric and gas service wholly within the State of New York, and is engaged in the production, transmission, distribution and sale of these services in a nine-county area centering around the City of Rochester.

The Company's territory, which has a population of approximately 900,000, is well diversified among residential, commercial and industrial consumers. In addition to the City of Rochester, which is the third largest city and a major industrial center in the State, it includes a large and prosperous farming area.



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Directors and Officers	*Inside Back Cover*

Our Cover

The color of our annual report cover this year duplicates the new color of our fleet vehicles. The old dark green is being replaced by "Doeskin Tan." Lighter colors provide added safety on the road.

The blue styled RG&E logo on our cover is also placed on the doors of the newly painted fleet vehicles.

Shareholder and Investor Relations Information

Inquiries regarding the Company's operations should be directed to David C. Heiligman, Vice President, Secretary and Treasurer of the Company.

Communications regarding changes of address, stock transfers, lost certificates or dividend payments should be directed to Chase Lincoln First Bank, N.A.

Corporate Office
89 East Avenue
Rochester, New York 14649
(716) 546-2700

Annual Meeting
May 17, 1989
At Rochester, New York

Listed
New York Stock Exchange
(Stock Symbol—RGS)

Transfer Agent and Registrar
Chase Lincoln First Bank, N.A.
Corporate Agency Department
Post Office Box 1250
Rochester, New York 14603
(716) 258-5874

Agent for Automatic Dividend Reinvestment and Stock Purchase Plan
(See page 35 for description of plan)
Chase Lincoln First Bank, N.A.
Corporate Agency Department
Post Office Box 1507
Rochester, New York 14603
(716) 258-5854

First Mortgage Bond Trustee and Paying Agent
Bankers Trust Company
Attention: Security Holder Relations
Post Office Box 9006
Church Street Station
New York, New York 10249
(212) 250-6000

Form 10-K Annual Report
The Company will provide, without charge, a copy of the Annual Report on Form 10-K filed with the Securities and Exchange Commission with respect to fiscal year 1988, upon written request of any shareholder addressed to the Secretary.

Market Price of Common Stock and Related Stockholder Matters

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

Preferred and common stock dividends were paid on March 31, June 30, September 30 and December 31. The Company presently estimates that none of the 1988 common or preferred stock dividends will constitute a return of capital and therefore all of such dividends are subject to Federal income tax as ordinary income.

The table below shows dividends per share for the Company's common stock and quoted market prices:

1988	Dividend paid per share	Price range High	Price range Low
1st Quarter	$ .30	$14	$12
2nd Quarter	.30	15½	12⅜
3rd Quarter	.30	15⅜	12⅞
4th Quarter	.30	14¼	12½
	$1.20		

1987	Dividend paid per share	Price range High	Price range Low
1st Quarter	$ .52	$19⅛	$15⅞
2nd Quarter	.52	17¼	14⅞
3rd Quarter	.30	17	14
4th Quarter	.30	14⅝	11⅛
	$1.64		

The common dividend rate was reduced effective the third quarter of 1987. The Company is currently paying cash dividends quarterly. Declaration of future dividends and levels of payments are necessarily dependent on future earnings, cash flow, financial requirements, the duration of, and costs associated with, the outage at Nine Mile Point Nuclear Station Unit No. 1 (Unit 1), the adequacy and timeliness of rate relief, the level of retained earnings out of which dividends can be declared and other uncertainties facing the Company (see Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes 10 and 11 of Notes to Consolidated Financial Statements). Also, restrictions in governing instruments and provisions of state law and the Federal Power Act may affect the declaration and payment of dividends. While the Company expects to continue the payment of dividends, management and the Board of Directors must take into account, in respect of future quarterly dividend declarations and the level of such dividends, the facts and elements referred to above in evaluating the decision to declare a dividend.

The holders of Common Stock are entitled to one vote per share but may not cumulate their votes for the election of Directors. Whenever dividends on Preferred Stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect a majority of the Board of Directors. Whenever dividends on any Preference Stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set apart for payment, the holders of such stock can elect two members to the Board of Directors. No dividends on Preferred Stock are now in arrears and no Preference Stock is now outstanding.

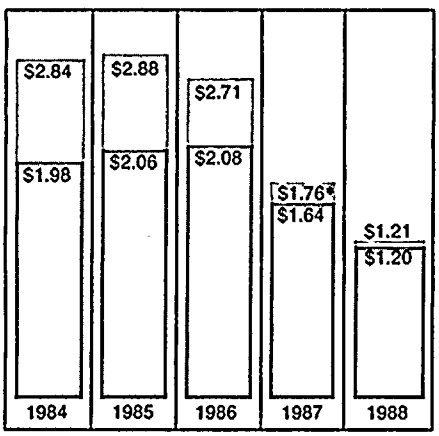
Upon any dissolution, liquidation or winding up of the Company's business, the holders of Common Stock are entitled to receive a pro rata share of all of the Company's assets remaining and available for distribution after the full amounts to which holders of Preferred and Preference Stock are entitled have been satisfied.

The indenture securing the Company's mortgage debt provides that surplus shall be reserved and held unavailable for the payment of dividends on Common Stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. Such provisions have never restricted the Company's surplus.

At year end, about 162,000 stockholders owned common shares of Niagara Mohawk and about 7,000 held Preferred Stock. The chart below summarizes common stockholder ownership by size of holding:

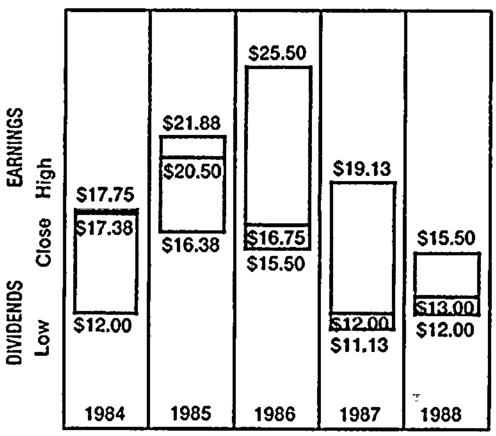
Size of holding (Shares)	Total stockholders	Total shares held
1 to 99	51,662	1,530,043
100 to 999	99,227	25,298,708
1,000 or more	10,661	108,804,345
	161,550	135,633,096

EARNINGS AND DIVIDENDS PAID PER COMMON SHARE

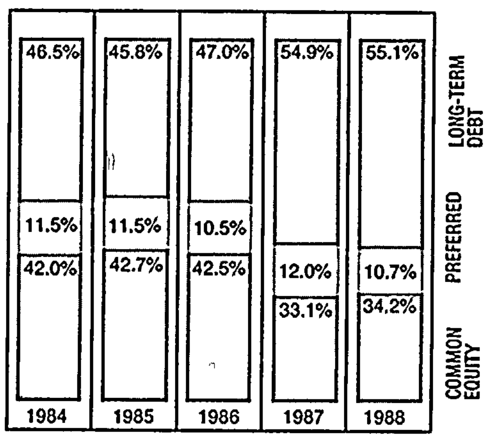


* excluding the effect of the write-off of disallowed Nine Mile Unit No. 2 costs ($6.54 per share).

COMMON STOCK PRICES



CAPITALIZATION RATIOS



Electric and Gas Statistics

ELECTRIC CAPABILITY

At January 1,	1989	%	1988	1987
	Thousands of kilowatts			
Thermal:				
Coal fuel				
Huntley, Niagara River	715	10	715	715
Dunkirk, Lake Erie	560	7	560	555
Total coal fuel	1,275	17	1,275	1,270
Residual oil fuel				
Albany, Hudson River**	400	6	400	400
Oswego, Lake Ontario***	1,571	21	1,572	1,563
Roseton, Hudson River	300	4	300	299
Middle distillate oil fuel				
19 Combustion turbine and diesel units	237	3	237	237
Total oil fuel	2,508	34	2,509	2,499
Nuclear fuel				
Nine Mile Point, Lake Ontario	1,054	14	610	610
Purchased—firm contract Power Authority— FitzPatrick, Lake Ontario	53	1	59	153
Total nuclear fuel	1,107	15	669	763
Total thermal sources	4,890	66	4,453	4,532
Hydro:				
Owned and leased hydro stations (78)	695	9	695	684
Purchased—firm contracts				
Power Authority—Niagara River	1,077	15	1,076	1,111
Power Authority— Blenheim-Gilboa Pumped Storage Plant	295	4	270	270
Other	294	4	285	262
Total hydro sources	2,361	32	2,326	2,327
Other purchases	121	2	97	80
Total capability*	7,372	100	6,876	6,939

	1988	1987	1986
Electric peak load during year	6,220	5,780	5,724

*Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems. Hydro station capability is based on average December stream-flow conditions.

**Has capability to burn natural gas (as well as oil) as a fuel.

***Oswego Unit 3 burns natural gas only.

The Nine Mile Point Unit No. 2, increased capability by 444,000 KW representing the Company's share of the output.

ELECTRICITY GENERATED AND PURCHASED

	1988	%	1987	%	1986	%
	Millions of kw-hrs.					
Thermal:						
Generated						
Coal	7,894	21	7,185	18	6,140	16
Oil	7,444	19	4,256	11	5,811	16
Nuclear	1,460	4	4,753	12	3,147	8
Natural gas	1,070	3	1,785	4	177	1
Purchased–						
Nuclear from Power Authority	306	1	700	2	1,284	3
Total thermal	18,174	48	18,679	47	16,559	44
Hydro:						
Generated	3,171	8	3,396	8	4,140	11
Purchased from						
Power Authority	7,014	18	7,378	19	7,683	20
Other	978	3	1,017	3	565	2
Total hydro	11,163	29	11,791	30	12,388	33
Other purchased power—various sources	8,804	23	8,942	23	8,692	23
Total generated and purchased	38,141	100	39,412	100	37,639	100

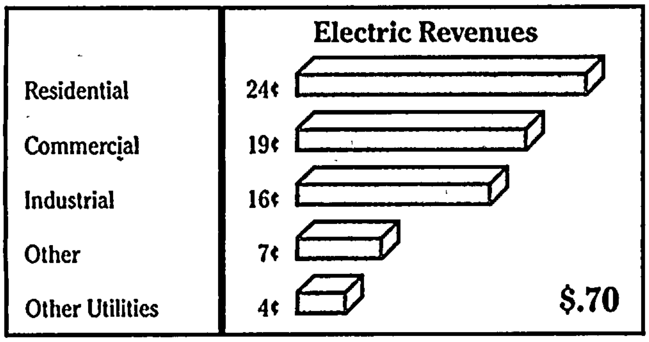
ELECTRIC STATISTICS

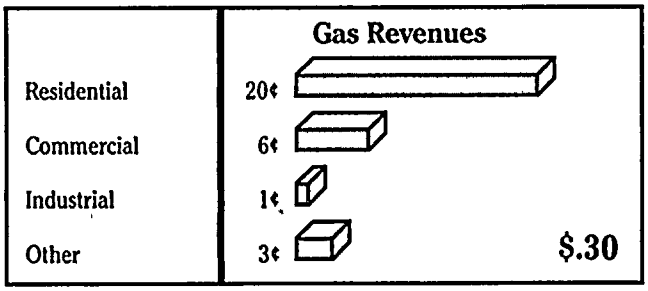
	1988	1987	1986
Electric sales *(Millions of kw-hrs.)*			
Residential	10,099	9,655	9,359
Commercial	11,182	10,718	10,374
Industrial	11,745	10,922	10,801
Municipal service	237	235	234
Other electric systems	1,732	4,154	3,579
	34,995	35,684	34,347
Electric revenues *(Thousands of dollars)*			
Residential	$ 805,523	$ 739,034	$ 702,309
Commercial	827,918	783,103	766,815
Industrial	458,332	435,518	448,855
Municipal service	41,231	40,603	41,031
Other electrical systems	60,214	118,021	95,809
Miscellaneous	150,514	53,912	77,014
	$2,343,732	$2,170,191	$2,131,833
Electric customers *(Average)*			
Residential	1,324,367	1,307,946	1,291,111
Commercial	140,237	138,193	136,304
Industrial	2,322	2,374	2,481
Other	3,182	3,400	3,282
	1,470,108	1,451,913	1,433,178
Residential *(Average)*			
Annual kw-hr. use per customer	7,626	7,382	7,249
Cost to customer per kw-hr.	7.98¢	7.65¢	7.50¢
Annual revenue per customer	$608.23	$565.03	$543.96

GAS STATISTICS

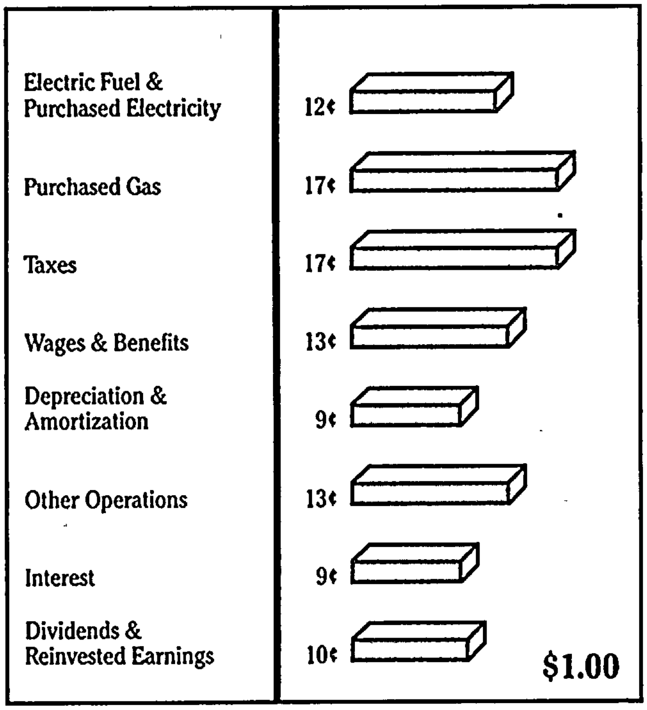
	1988	1987	1986
Gas Sales *(Thousands of dekatherms)*			
Residential	51,065	48,054	49,430
Commercial	23,951	23,520	27,218
Industrial	4,274	7,242	15,575
Other gas systems	2,158	2,504	3,724
Total sales	81,448	81,320	95,947
Transportation of customer-owned gas	27,244	21,862	4,868
Total gas delivered	108,692	103,182	100,815
Gas revenues *(Thousands of dollars)*			
Residential	$289,026	$280,092	$296,853
Commercial	119,929	121,145	142,807
Industrial	19,008	29,733	68,476
Other gas systems	9,363	8,802	14,300
Transportation of customer-owned gas	13,841	11,551	2,244
Miscellaneous	5,554	1,916	3,806
	$456,721	$453,239	$528,486
Gas customers *(Average)*			
Residential	417,360	411,566	407,546
Commercial	35,017	33,974	33,248
Industrial	323	395	465
Other	2	2	2
Transportation	403	184	40
	453,105	446,121	441,301
Residential *(Average):*			
Annual dekatherm use per customer	122.4	116.8	121.3
Cost to customer per dekatherm	$5.66	$5.83	$6.01
Annual revenue per customer	$692.51	$680.55	$728.39
Maximum day gas sendout *(dekatherms)*	818,128	758,914	786,165

Source of 1988 Revenue Dollar





Use of 1988 Revenue Dollar



Financial Highlights

Sales, Revenues and Earnings (Thousands, Except Per Share Amounts)	1988	1987	% Change
Electricity to customers			
Kilowatt-hours	6,197,117	5,948,763	4
Revenue	$ 513,617	$ 489,215	5
Electricity to other utilities			
Kilowatt-hours	1,149,900	1,047,654	10
Revenue	$ 29,966	$ 26,215	14
Gas			
Therms sold and transported	483,766	445,591	9
Revenue	$ 230,395	$ 216,058	7
Total operating revenues	$ 773,978	$ 731,488	6
Total operating expenses	$ 635,104	$ 609,113	4
Operating income	$ 138,874	$ 122,375	13
Nine Mile Two write-off, net	—	$ 262,000	—
Net income (loss)	$ 76,114	$ (168,711)	—
Earnings (loss) applicable to common stock	$ 68,766	$ (176,858)	—
Weighted average number of common stock shares outstanding	30,513	29,728	3
Earnings (loss) per common share	$2.25	$(5.95)	—
Cash dividends paid per common share	$1.50	$2.025	(26)
Rate of return on average common equity*	12.68%	12.45%	2
Book value per common share—year end	$17.69	$16.98	4
Utility Plant (Thousands)			
Capital expenditures, less allowance for funds used during construction	$ 110,587	$ 120,965	(9)
Net utility plant at December 31	$1,510,090	$1,474,746	2
Number of Customers at December 31			
Electric	321,643	317,033	1
Gas	254,143	250,124	2
Number of Common Stock Shareholders at December 31	41,834	44,127	(5)
Number of Employees at December 31	2,600	2,558	2

**Excludes disallowed Nine Mile Two costs written off in 1987.*

Letter to Shareholders

The Year 1988: For your Company, 1988 was a good year. Revenues, earnings per share and unit sales of electricity and gas all increased. Also, and perhaps more significant, the Nine Mile Two nuclear power plant was completed and went into commercial operation in the spring.

Nine Mile Two Completed: The plant's completion was a long-awaited event that culminated 13 years of RG&E involvement with a 14 percent share of ownership in the project. The delays in construction, periods of high interest and inflation rates, additional regulatory requirements and a series of technical problems made recent years the most difficult in our long corporate history.

≡ The plant ran reasonably well during its initial period of operation. On October 1, the plant was taken out of service for scheduled maintenance and inspection. In December, senior managers of the U.S. Nuclear Regulatory Commission (NRC) conducted their nationwide biannual review of nuclear power plant performance. On December 20, the NRC advised Niagara Mohawk Power Corporation, operator of the plant, that they will be closely monitoring Nine Mile Two. Plants selected for close monitoring are those identified as having operational weaknesses that call for closer attention.

≡ Niagara Mohawk Power Corporation is working to correct the problems and relieve the concerns raised by the NRC. Niagara advises that the outage will continue until mid-February 1989, delaying until late February the unit's return to full power.

Sales: We saw continued healthy growth in unit sales of electricity and gas in 1988. A prevailing strong economy in our service territory helped advance 1988 unit sales over the previous year's levels. Kilowatt-hour sales to customers for the year were up 4.2 percent. Therms of gas sold and transported rose 8.6 percent. In 1988 we added 4,600 electric customers and 4,000 gas customers. This was the 4th consecutive year in which customer growth maintained record levels.

≡ Weather also favorably affected 1988 revenues and unit sales. A very hot summer brought heavy use of air conditioning equipment. On August 3, a new summer peak electric load record of 1,275,000 kilowatts was set. This was 5.8 percent above the previous summer peak reached in July of 1987.

Earnings: Improved revenues in 1988 provided a welcome gain in earnings. Per-share earnings of common stock for 1988 were \$2.25 compared with \$2.12 per share in 1987 excluding the effect of the Nine Mile Two write-off. Including a write-off of \$262 million for disallowed Nine Mile Two costs, 1987 earnings showed a loss of \$5.95 per share.

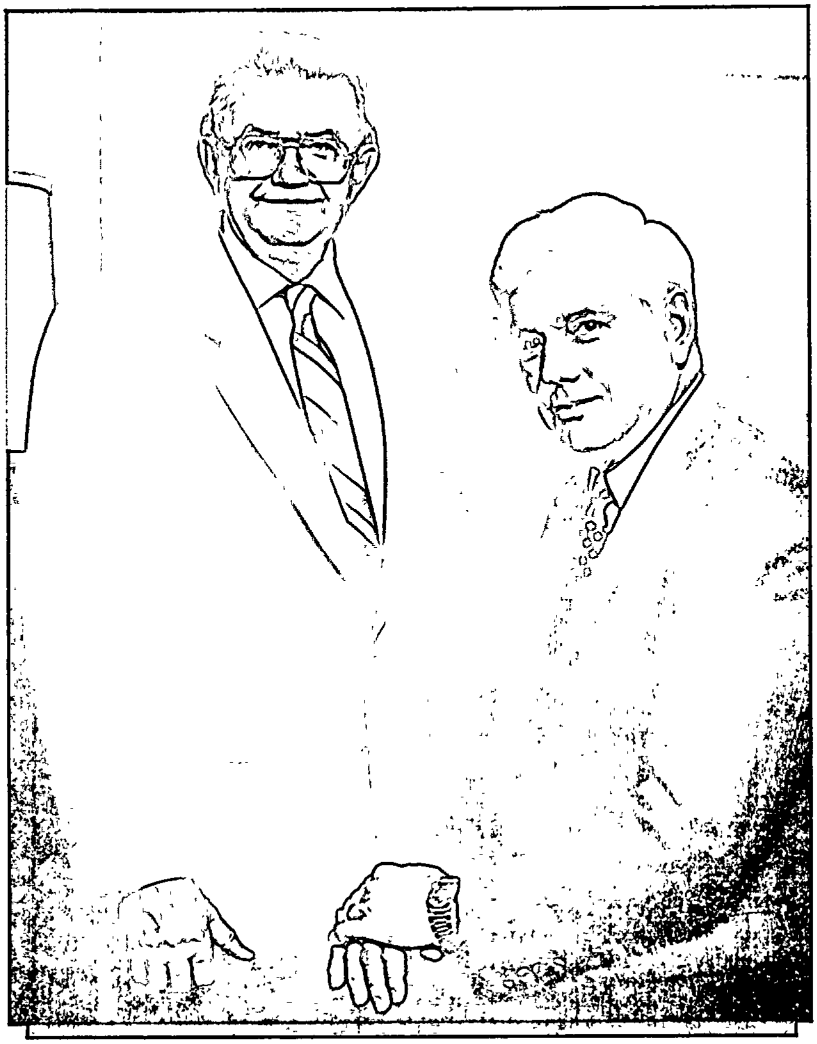
Retained Earnings and Dividends: In 1987, the Company wrote off \$262 million as its share of the settlement agreement reached between the Nine Mile Two cotenants and the New York State Public Service Commission (PSC) (see Note 10 on page 28). That write-off forced us to reduce the annual common stock dividend from \$2.20 a share to \$1.50 a share.

≡ We plan to rebuild retained earnings to a level at least equal to the annual dividend requirement for both common and preferred shares before considering any increase in the common stock dividend rate.

≡ During 1988 we were able to rebuild retained earnings from \$17.6 million at the beginning of the year to \$39.7 million at year's end.

Electric Capacity: Our share of the Nine Mile Two capacity, or 151,000 kilowatts, gives us sufficient baseload capacity to meet expected electric demand well into the 90s. Also contributing to our capacity is our contract that allows us to continue buying inexpensive hydroelectric power from the New York Power Authority. The original contract was to have expired at the end of 1989. The new contract that extends hydropower purchases through the year 2007 provides continued benefits for our residential electric customers and helps keep RG&E competitive.

≡ A good electric generation mix also keeps us competitive. We have a mix of coal, hydroelectric and nuclear generated electricity. More than half of our customers' electric requirement is supplied by nuclear power from our wholly owned and operated Ginna nuclear power plant and from our share of the Nine Mile Two plant. Nuclear fuel still holds a substantial cost advantage over alternatives, including coal.



Harry G. Saddock (l) and Roger W. Kober.

The Ginna Plant: In 1988, the Ginna nuclear plant again had an excellent operating record. The plant was available 86 percent of the time. That's a high rating compared with the national average for nuclear power plant availability as is the plant's 85 percent capacity factor for the year. Capacity factor is a measure of how much of the plant's potential production was achieved.

Rate Stabilization: In 1988, RG&E reached an agreement with the PSC that the Company will not ask to raise electric or gas rates to be effective before July 1, 1990. This agreement will have kept the base rates for electricity and gas unchanged for at least two and a half years, stabilizing rates for our customers and helping to promote business expansion in our nine-county service territory.

Capital Requirements: With the completion of the Nine Mile Two plant, our capital needs have been reduced from previous years. We are in a position to finance most of our capital requirements from internal sources. We did, however, take advantage of a tax-exempt bond issue last December that provided $25.5 million at an eight and three-eighths percent interest rate.

Diversification: We made our first entry into a diversified, wholly owned subsidiary in 1988 when we created a company called Utilicom. This venture, with a modest capitalization of $1 million, is creating and marketing computerized interactive video training software for use in commerce and industry. The company also produces software that makes environmental regulatory compliance record keeping much simpler.

≡ While the Company may consider other diversification opportunities, the Utilicom venture is the only such diversification we plan for the time being. We intend to stay close to our primary business—energy production, service and sales.

Leadership Recognized: We want to recognize the valuable contributions in corporate leadership made by former Chairman of the Board and Chief Executive Officer Paul W. Briggs and former Vice Chairman of the Board Keith W. Amish. Paul retired on December 1 after 43 years of service, and, after 41 years at RG&E, Keith retired on September 1. Each guided the Company through the difficult Nine Mile Two period, and each agreed to postpone regular retirement to see the Company through to the commercial operation of the plant. With their guidance the Company weathered the difficult financial and regulatory years created by the Nine Mile Two project. All of us, employees, shareholders and customers owe Paul and Keith a great deal.

The Outlook—Becoming the Best: We expect to see more competition as deregulation of energy markets intensifies. Deregulation will bring about profound changes for us and our customers. While we can't now predict when, how and who will benefit from the changes, we are convinced there is only one strategy that can be successful in the competitive arena—become the best.

Becoming the best is a consensus reached by your senior management. We've spent a good deal of time identifying specific goals for the future, and pinning down our corporate mission.

Our mission is to be the preeminent private utility in New York State operating as an effective supplier of energy and related services by optimizing customer satisfaction, investor return and employee achievement.

We set several identifiable five-year goals.

- Increase customer satisfaction
- Promote employee and public safety
- Optimize employee achievement
- Attain decreases in the real cost of our products
- Earn the allowable return on equity
- Increase sales margins
- Develop flexible price structures to recognize competition
- Implement innovative use of assets
- Develop conservative diversification projects

We believe we are on the right track. We have our mission before us with specific goals to achieve. The Nine Mile Two project is completed. A rate freeze, continuing cost control measures, fine productivity from our dedicated employees, a new consumer program known as Customer Connection and an aggressive marketing effort combine to move us into a strong tomorrow.

We are optimistic at RG&E. There are new challenges ahead in this business. We believe we have the talent, people and drive to make the challenges work for us, our customers, and for you, the shareholders. We will become the best.

Harry G. Saddock

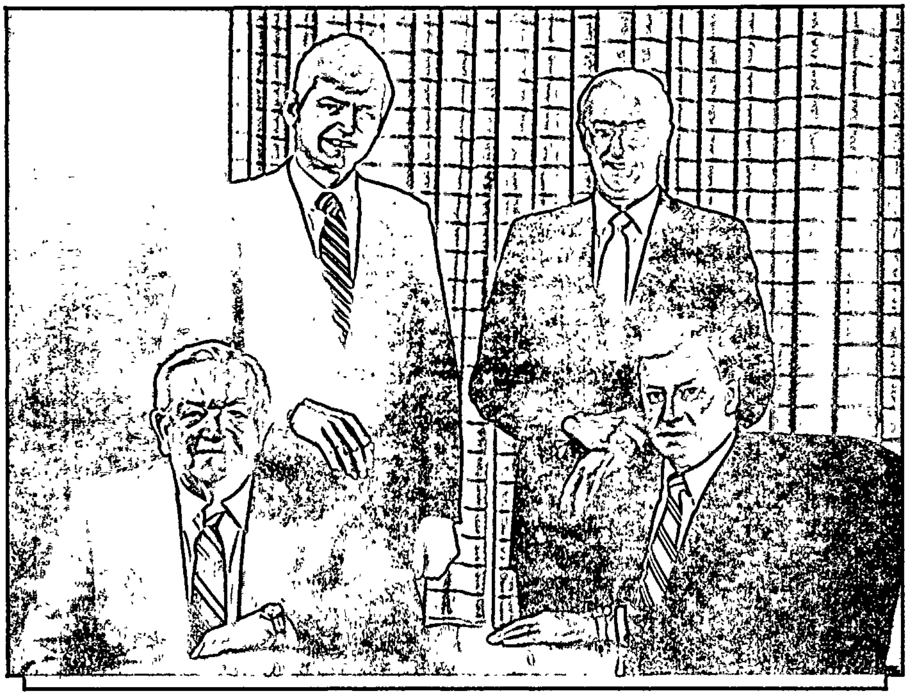
Harry G. Saddock
Chairman of the Board
and Chief Executive
Officer

Roger W. Kober

Roger W. Kober
President
and Chief Operating
Officer

February 3, 1989

Management Appointments



Clockwise from upper left: Robert E. Smith, Wilfred J. Schrouder, Jr., David C. Heiligman, and Howard E. Rowley.

On June 15, 1988, the board of directors elected Harry G. Saddock as chairman of the board and chief executive officer and Roger W. Kober as president and chief operating officer. Those appointments became effective upon the retirement of former Chairman of the Board and Chief Executive Officer Paul W. Briggs on December 1, 1988. Former Vice Chairman of the Board Keith W. Amish retired on September 1, 1988.

In other appointments, David C. Heiligman was named vice president, secretary and treasurer of the corporation.

Howard E. Rowley was appointed vice president, gas and transportation.

Wilfred J. Schrouder, Jr. became vice president, employee relations and public affairs.

Robert E. Smith was appointed vice president, production and engineering.

Board Appointments

M. Richard Rose

Roger W. Kober

At the 1988 annual meeting of shareholders in May, M. Richard Rose, Ph.D. was elected to the board of directors. He is president of the Rochester Institute of Technology (RIT), a position he has held since 1979. Dr. Rose replaced Paul A. Miller, president emeritus and professor at RIT, who retired from the board after 14 years of service as a director.

President and Chief Operating Officer Roger W. Kober was elected to the board of directors effective December 1, 1988.

The following is Management's assessment of significant factors which have affected the Company's financial condition and operating results. As indicated below, the Company's participation in the Nine Mile Two project has had and will continue to have a substantial impact on its financial condition and earnings. In the spring of 1988, Nine Mile Two entered commercial operation marking the completion of the construction and pre-operational testing phases of the project.

Nine Mile Two

The Company owns a 14 percent share of the Nine Mile Two facility, a 1,080,000 kilowatt nuclear generating unit that was constructed and is being operated by Niagara Mohawk Power Corporation (Niagara) near Oswego, New York. The Company's primary capital commitment over the past several years has been for the construction of this facility and, in the spring of 1988, construction was completed and the unit entered commercial service. Niagara is operating the unit on behalf of all owner cotenants pursuant to a full power operating license which the Nuclear Regulatory Commission (NRC) issued on July 2, 1987 for a 40-year term beginning October 31, 1986. The NRC in December 1988 added Nine Mile Two to its list of nuclear plants which require "close monitoring" by it, a category of plants identified as having weaknesses warranting such attention. The NRC's action came during an outage of Nine Mile Two for repairs and planned maintenance. Niagara has advised the Company that the outage will continue until mid-February 1989, delaying until late February the unit's return to full power.

In October 1986, the New York State Public Service Commission (PSC) issued an order approving a settlement proposal (Nine Mile Two Settlement) which limits to $582 million (less prepaid financing charges currently estimated at $96 million) the amount of Nine Mile Two construction costs which may be included in the Company's rate base. As a result of a rate agreement approved by the PSC in July, 1988, the Company's full investment in allowable Nine Mile Two capital costs, assuming an April 15, 1988 commercial operation date, has now been included in rate base for the rate year beginning August 1, 1988.

The PSC has fixed April 5, 1988 as the Nine Mile Two commercial operation date for Niagara and Long Island Lighting Company, two of the project's five cotenants. The PSC has not yet taken formal action on the subject with respect to the rates and accounts of the Company. The Company's 1988 rate case settlement utilized a hypothetical date of April 15, 1988 for commercial operation of Nine Mile Two, but contemplated that an actual commercial operation date might be separately adopted. The Company believes it likely that the PSC will ultimately select April 5, 1988, as the appropriate commercial operation date for the Company.

In 1987, the Company wrote off $262 million (net of tax) of its investment in Nine Mile Two (see Rate Base, Accounting Change and Regulatory Policies) in recognition of the Nine Mile Two Settlement. The Company will recognize any adjustment in that amount necessary to conform to the PSC recognized commercial operation date. A change from the May 15, 1988 commercial operation date assumed by the Company in the 1987 write-off will result in additional income or loss of approximately $6 million (net of tax) per month. PSC confirmation of the commercial operation date as of April 5, 1988, would diminish the Company's loss. However, as presented in Note 10 of the Notes to Financial Statements, resolution of certain items currently being disputed with the PSC could result in other adjustments to the loss recognized by the Company. The Company is unable to determine at this time the adjustment necessary, if any, to recognize the resolution of these outstanding issues with respect to the Nine Mile Two Settlement.

In September 1988 the Company received $40.6 million from Niagara as part of the Nine Mile Two Settlement. This reimbursement had been recognized in 1987 in determining the $262 million Nine Mile Two write-off described above. Refer to Note 10 of the Notes to Financial Statements for additional information regarding the Company's investment in Nine Mile Two.

Liquidity and Capital Resources

The combination of $40.6 million in cash received from Niagara as discussed above, lower construction expenditures, additional refunding of higher cost securities, and the full-year effect of the 1987 rate increase improved the Company's cash flow in 1988.

Capital Requirements

The Company's capital requirements for the three-year period 1986–1988 and the current estimate of capital requirements through 1991 are summarized in the table on page 7.

For the period 1989 to 1991, the Company anticipates construction requirements to average approximately $120 million per year. In addition to its construction expenditures, the Company has mandatory securities maturities and sinking fund obligations, which total approximately $100 million over the next three years through 1991.

Included in the table on page 7 are the carrying charges, or financing costs, associated with major projects under construction. These carrying costs become a part of the capitalized cost of the related project. The Company begins to earn a cash return on its investment, including these carrying costs, when the cost of the project is included in rate base, which generally is at the time such project is

Capital Requirements

Type of Facilities	Actual 1986	1987	1988	Projected 1989	1990	1991
	(Millions of Dollars)					
Electric Property:						
Production	$101	$ 60	$ 39	$ 46	$ 32	$ 26
Transmission and Distribution	25	22	28	24	34	32
Street Lighting and Other	2	2	1	3	3	2
Subtotal	128	84	68	73	69	60
Nuclear Fuel	12	16	17	19	17	20
Total Electric	140	100	85	92	86	80
Gas Property	13	14	15	16	15	15
Common Property	7	7	7	11	13	14
Total	160	121	107	119	114	109
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	45	8	4	4	6	5
Deferred Financing Charges Included in Other Income	5	6	1	2	2	—
Total Construction Requirements	210	135	112	125	122	114
Securities Redemptions, Maturities and Sinking Fund Obligations*	55	91	69	35	25	40
Total Capital Requirements	$265	$226	$181	$160	$147	$154

**Excludes prospective refinancings.*
Note: AFUDC in 1986 has not been restated to reflect the disallowance of certain Nine Mile Two plant costs recognized by the Company in 1987.

put into service. Certain Nine Mile Two plant construction costs, however, were included in rate base prior to commercial operation. This action, while reducing the amount of AFUDC, enhanced the Company's cash flow at such time. With the full recognition of allowable Nine Mile Two plant construction costs now in rate base (see Rate Base, Accounting Change and Regulatory Policies) and construction projects of a shorter duration than Nine Mile Two, the Company expects the level of AFUDC to stabilize in the $4 million to $6 million range for the next several years. In addition to AFUDC, carrying charges include the recognition of certain customer prepaid financing costs discussed below under Rate Base, Accounting Change and Regulatory Policies.

1988 Capital Requirements. With the completion and commercial operation of Nine Mile Two, construction expenditures for the year dropped to $112 million, well below the average for the prior two years. Electric production plant requirements for 1988 included $17 million of expenditures made at the Company's Ginna nuclear plant and $16 million of expenditures for Nine Mile Two, including $3 million for post-in-service projects. The Company also invested $26 million to upgrade electric distribution facilities to maintain customer service standards for both existing and new customers. In addition, the Company spent $17 million for nuclear fuel, largely at the Ginna nuclear plant.

In the Gas Department, the replacement of older gas services, the relocation of gas mains for highway improvement, and the installation of gas services for new load resulted in construction expenditures of $16 million, including AFUDC, in 1988.

Total capital requirements in 1988 also included mandatory sinking fund obligations totaling approximately $3.6 million. As discussed under Liquidity, Financing and Capital Structure, the Company was also able to lower its cost of capital in 1988 by redeeming approximately $60 million of high-cost senior securities.

Projected Capital Requirements. With no specific plans for major additions to generating capacity, the Company expects to carry out a program to extend the operating life of existing generating units and to make ongoing modifications to the Ginna nuclear plant and Nine Mile Two. In addition, the Company's construction program will focus on the need to serve new customers, to provide for the replacement of obsolete or inefficient utility property and to modify facilities consistent with the most current environmental and safety regulations. The projected 1989 construction requirements reflect primarily additional expenditures at the Ginna nuclear plant associated with its second mandatory ten-year in-service inspection in 1989, plant modifications to comply with recent NRC directives and overall efforts to maintain the high standards of performance the Company has set for the plant.

In addition to its projected construction requirements, the Company also has future maturities and sinking fund obligations as indicated in the table above and may consider, as conditions warrant, the redemption or refinancing of certain long-term securities.

The Company's capital expenditures program is under continuous review and will be revised depending upon the progress of major construction projects, customer demand for energy, rate relief, government mandates and other factors.

Liquidity, Financing and Capital Structure

During 1988, lower construction requirements, compared with prior years, improved cash flow and limited the need to obtain external financing. Internally generated funds were sufficient to fund the Company's capital requirements for the year. Notwithstanding the Company's strong cash position, new common stock shares were issued through the ongoing Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan) which improved common equity capitalization. In addition, the Company obtained low-cost tax-exempt financing with the issuance of a new series of first mortgage bonds in connection with a Nine Mile Two pollution control financing. A strong cash position enabled the Company to retire certain high-cost senior capital obligations without having to refinance such redemptions. Such refundings contributed to a drop in the Company's embedded cost of debt from 8.90% at the end of 1987 to 8.71% at year-end 1988. Likewise, the Company's embedded cost of preferred stock was 6.72% at the end of 1988 compared with 7.09% a year earlier.

With construction activity as presently projected and the Company's current cash position, the Company anticipates it will not require additional long-term financing to meet its capital requirements for the next several years. Should capital requirements exceed current estimates and create the need for external financing, the Company anticipates utilizing its revolving credit agreement. Certain of the Company's financial agreements contain covenants which may restrict the Company's ability to incur additional indebtedness if the need for external financing is beyond that provided by the Company's revolving credit agreement.

Financing. Interim financing is available through short-term borrowings with bank notes and commercial paper. To replace an expiring revolving credit agreement, a new agreement totaling $90 million and effective December 1, 1988 was negotiated by the Company with certain domestic banks. Certain restrictive covenants contained in the Company's prior revolving credit agreement and relating to Nine Mile Two were removed in the new agreement, thereby enabling the Company to obtain greater short-term financing flexibility. The new revolving credit agreement expires December 1, 1991, but may be extended annually for a successive three-year period. At December 31, 1988, the Company had no short-term debt outstanding.

The Company's Certificate of Incorporation (Charter) provides that unsecured debt may not exceed 15 percent of the Company's total capitalization (excluding unsecured debt) without the approval of at least a majority of the holders of outstanding preferred stock. As of December 31, 1988, the Company would be able to incur approximately $6 million of unsecured debt under this provision before needing to obtain the required approval as indicated. In order to be able to use its revolving credit agreement, the Company has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of the Company's Charter.

As part of the Company's continuing program to improve its capital structure and reduce its embedded cost of capital, two security issues were redeemed in 1988. On November 1, 1988, $40 million of First Mortgage 11¾% Bonds, Series NN, were redeemed at a redemption price of 105.22 percent of the principal amount; and on December 1, 1988, 183,108 outstanding shares of 8.60% Preferred Stock, Series P, were redeemed at the redemption price of $105 per share. Payment for these redemption transactions was provided out of cash and temporary cash investments. The December redemption of Series P Preferred Stock followed an open-market purchase and sinking fund redemption earlier in the year, which totaled approximately 33,000 shares, thereby eliminating all outstanding shares of Series P stock.

In December 1988, the Company issued $25.5 million of First Mortgage 8⅜% Bonds, Series OO, to secure an equal amount of tax-exempt pollution control revenue bonds issued by the New York State Energy Research and Development Authority. Proceeds from this financing were used to reimburse the Company for prior expenditures associated with the Company's share of certain pollution control facilities at Nine Mile Two.

The Company in 1988 raised a total of $10.4 million to finance its capital expenditures program by issuing approximately 619,000 shares of common stock through its ADR Plan. To meet the demands of its construction program and to maintain a prudent capital structure, the Company over the past three years has issued common stock at a market price below the book value per share. Such sales have had a dilutive effect on the book value per share at the time of issuance. The Company's book value per share did increase, however, during 1988. Book value per share at December 31, 1988 was $17.69. Per-share book value of $16.98 at December 31, 1987 was significantly lower than the $24.93 book value per share a year earlier and reflects the net Nine Mile Two write-off in 1987 of $262 million ($8.81 per share).

Capital Structure. The Company's retained earnings at December 31, 1988 were $39.7 million, up approximately $22 million compared with a year earlier. Approximately 38.0 percent of the Company's capitalization at December 31, 1988 was comprised of common equity (including retained earnings), with the balance being comprised of 6.7 percent preferred equity and 55.3 percent long-term debt. These percentages are based on the Company's capitalization exclusive of its long-term liability to the Federal Department of Energy (see Note 1 of the Notes to Financial Statements). The Company's retained earnings reflect a $262 million write-off in 1987 for disallowed Nine Mile Two plant costs as discussed below under the heading Rate Base, Accounting Change and Regulatory Policies. Upon resolution of certain regulatory issues associated with the Nine Mile Two plant, adjustments may be required which could increase or decrease the Company's retained earnings as discussed in Note 10 of the Notes to Financial Statements. It is the Company's intention to move to a less leveraged capital structure through growth in retained earnings and the retirement of long-term debt through mandatory sinking fund redemptions and maturities. To improve its capital structure, the Company will also consider the optional redemption of high-cost senior securities.

Rate Increases

Granted

Class of Service	Effective Date of Increase	Amount of Increase (Decrease) (Annual Basis) (000's)	Percent Increase (Decrease)	Authorized Rate of Return on Rate Base	Authorized Rate of Return on Equity
Electric	February 1, 1985	$ 4,535*	0.9%	12.52%	16.00%
	July 14, 1985	5,799	1.3	12.09	15.00
	January 2, 1986	2,845*	0.6	12.09	15.00
	July 20, 1986	20,895	4.4	10.75	12.60
	January 2, 1987	1,223*	0.2	10.75	12.60
	July 17, 1987	16,198	3.4	10.48	13.20
	January 4, 1988	2,413*	0.5	10.48	13.20
	July 26, 1988	—	—	10.39**	13.40
Gas	July 14, 1985	157	0.1	12.09	15.00
	July 20, 1986	(3,185)	(1.1)	10.75	12.60
	January 2, 1987	458*	0.2	10.75	12.60
	July 17, 1987	—	—	10.48	13.20
	July 26, 1988	—	—	10.39**	13.40

**Second step increase allowed.*
***For the year beginning August 1, 1989, the authorized rate of return on rate base is 10.46%.*

Rate Base, Accounting Change and Regulatory Policies

In June 1988, the Company, PSC staff, the New York State Consumer Protection Board and other intervening parties to the Company's pending rate case, negotiated a rate settlement (the 1988 Rate Agreement) which was approved by the PSC one month later. The 1988 Rate Agreement freezes the Company's base rates for electric and gas service at their present levels through at least June 1990. As part of the 1988 Rate Agreement, the Company was permitted to include the balance of allowable Nine Mile Two capital costs in rate base beginning August 1988. A summary of recent PSC rate decisions is presented in the table to the upper right.

Accounting Change. The Company's accounting policies conform to generally accepted accounting principles as prescribed by the Financial Accounting Standards Board (FASB) and applied to New York State utilities giving effect to the rate-making and accounting policies of the PSC. In September 1987 the Company adopted revised financial accounting principles prescribed by the FASB for disallowed plant costs (Statement of Financial Accounting Standards No. 90) and recognized for financial accounting purposes an aggregate $262 million after-tax write-off of disallowed Nine Mile Two plant costs based on a 1986 settlement agreement, discussed below, with the PSC.

The 1987 net of tax write-off includes the cumulative effect on retained earnings as of January 1, 1987 of $193 million, the reversal of $22 million of AFUDC recognized during the year and an additional $47 million to reflect other costs recognized during 1987. The Company reflected the cumulative effect of the accounting change of $193 million in its Statement of Income rather than restating previously issued financial statements. Accordingly, the net disallowance was presented separately for the effect prior to January 1, 1987, and for the portion of the disallowance which became known during 1987. No amounts of disallowed costs were recognized in 1988. The ultimate amount of disallowed Nine Mile Two costs to be recognized by the Company cannot presently be determined because of the uncertainties associated with the implementation of the Nine Mile Two Settlement, as previously discussed.

New York State Public Service Commission (PSC). The October 1986 PSC order approving the Nine Mile Two Settlement limits to $582 million (less prepaid financing charges) the amount of Nine Mile Two plant construction costs which may be included in the Company's rate base. The Nine Mile Two Settlement, which is under judicial challenge, resolved a proceeding established by the PSC in July 1985 to investigate the prudence of costs relating to the construction of Nine Mile Two. To implement the Nine Mile Two Settlement, the PSC for rate-making purposes reduced the Company's equity component of total capitalization, used to calculate the Company's cost of capital, effective August 1987. This action, which assumed a commercial operation date of February 15, 1988, effectively reduced future revenues by reducing the base on which future rates would be calculated.

As mentioned above, the 1988 Rate Settlement permits the Company to include its allowable Nine Mile Two capital costs in rate base beginning August 1, 1988. Also, essentially all operating and maintenance expenses for plant operation are reflected in rates. Other major provisions of the 1988 Rate Settlement include:

- Agreement by the Company to no changes in electric and gas base rates through at least June 1990.
- An equal sharing between customers and shareholders of any earnings above the authorized return on common equity of 13.4%.
- Authority to include in income $42 million in unbilled revenues and $5 million in deferred Nine Mile Two revenues over the two-year period ending July 31, 1990. (See Operating Revenues and Sales.)
- Permission to eliminate by offset one-half of the deferred debit and credit balances in connection with the unused portion of customer prepaid financing costs associated with Nine Mile Two (see following paragraph).

Rate decisions prior to the 1988 Rate Settlement had allowed the Company to include up to $430 million of Nine Mile Two plant costs in rate base. This action had enhanced the Company's cash flow and reduced the amount of AFUDC because AFUDC was not accrued on those amounts included in rate base. A comparable amount, however, calculated similarly to AFUDC and representing customer prepaid financing costs, was calculated up to commercial operation and recorded on the Balance Sheet as a liability, shown as a deferred credit. An equivalent amount was recorded as a deferred asset on the Company's Balance Sheet, since it represents deferred financing costs (or AFUDC) which are expected to be recovered over the life of the facility through amortization, if the PSC chooses to utilize these amounts to moderate customer rates. As permitted by the 1988 Rate Settlement, the Company in July 1988 eliminated one-half of these deferred balances by offset (that is, equal amounts of both the deferred debit and deferred credit balances were eliminated), and the remainder, estimated at approximately $45 million, will be eliminated by July 31, 1992 if not used prior thereto as non-cash earnings for rate moderation purposes. The 1988 Rate Agreement allows the Company to amortize $4.1 million of the $44.7 million deferred credit balance to Other Income for the rate year ending July 31, 1990, with a corresponding increase to the Company's rate base. Amortization of these deferred credits totaled $10.9 million through December 31, 1988.

Under the 1988 Rate Agreement, the Company agreed to exclude from rate base certain post-in-service Nine Mile Two capital additions pending review of such expenditures by the PSC. The PSC has allowed the Company to accrue carrying charges (AFUDC) on these expenditures until final consideration for inclusion in rate base is made. The 1988 Rate Agreement contemplated a separate proceeding late in 1988 to examine these amounts, currently estimated at $13 million. The Company is unable to predict what position the PSC will ultimately adopt or what adjustments to the Company's capitalization will be required.

In May 1988 the PSC ordered that take-or-pay (TOP) charges from gas pipeline suppliers should be deferred by the Company and other New York State gas distribution companies until the PSC determines if the gas distribution companies should be required to absorb any portion of the TOP charges. In October 1988 the PSC appeared to have concluded that it could deny recovery of TOP costs billed by an interstate pipeline supplier and paid by a gas distribution company. The Company has sought rehearing of that apparent conclusion but, as of mid-January 1989, the Company had not received a response from the PSC. The PSC has scheduled hearings to determine whether gas distribution companies should be required to absorb some portion of such TOP costs and how that portion recoverable from customers should be allocated among them. Staff of the PSC and the Company have entered into an interim settlement which would permit the Company to recover from customers 65% of the TOP costs during the continuation of the PSC proceeding but other parties to the proceeding oppose this interim settlement and the PSC had not acted on it as of mid-January 1989. At December 31, 1988 the Company had deferred $1.1 million of billed TOP charges. The Company is unable to estimate either the amount which may ultimately be included in its pipeline suppliers' charges to it for TOP charges, or the amount which it will be allowed to recover from customers.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1988 to 1987 and 1987 to 1986. The Notes to Financial Statements on pages 19 to 34 of this report contain additional information. Upon the commercial operation of Nine Mile Two, recognized by the Company in April 1988, the Company began to record operating revenues and operating expenses associated with the plant's operation.

Operating Revenues and Sales

Compared with the prior year, operating revenues increased six percent in 1988 after declining two percent in

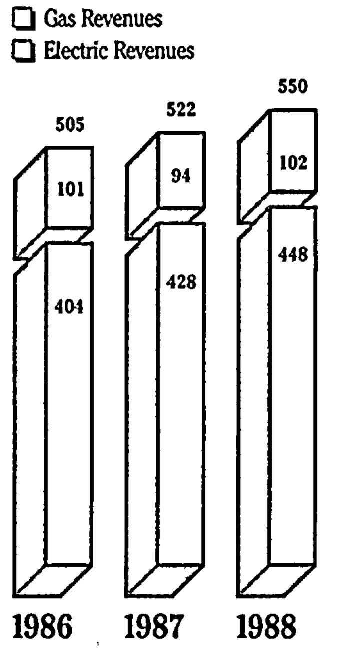
Operating Revenues

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	Electric Department 1988	Electric Department 1987	Gas Department 1988	Gas Department 1987
Customer Revenues (Estimated) from:				
Rate Increases	**$ 12,029**	$ 19,924	**$ (37)**	$ (1,499)
Unbilled Revenues	**7,198**	—	**1,330**	—
Fuel Clause Adjustments	**(19,378)**	(11,841)	**(2,152)**	(18,865)
Weather Effects (Heating)	**660**	(559)	**9,187**	(8,551)
Customer Consumption	**15,205**	11,340	**11,672**	(2,654)
Transportation Gas	**—**	—	**(6,174)**	(16,442)
Other	**8,688**	3,855	**511**	2,381
Total Change in Customer Revenues	**24,402**	22,719	**14,337**	(45,630)
Electric Sales to Other Utilities	**3,751**	5,750	**—**	—
Total Change in Operating Revenues	**$ 28,153**	$ 28,469	**$ 14,337**	$ (45,630)

Operating Revenues less Fuel Expenses

(Millions of Dollars)



Both electric and gas revenues in 1988 showed increases compared with 1987.

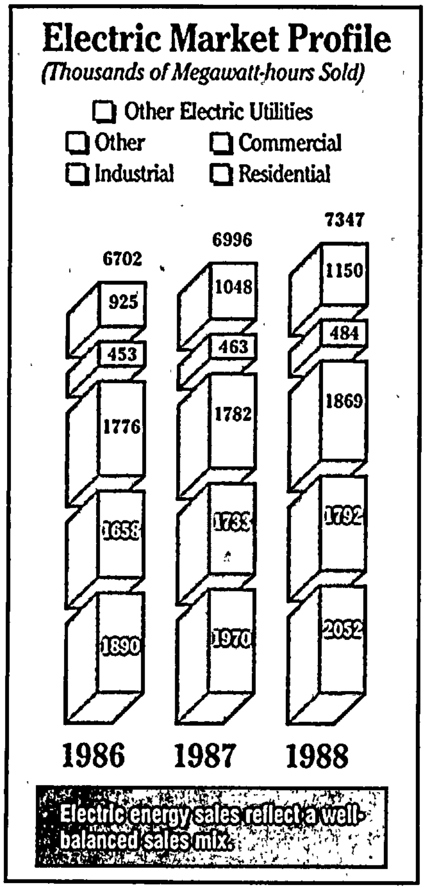
1987. Details of the revenue changes are presented in the table above. Operating revenues less fuel expenses were also up in 1988 as shown in the graph to the right.

Electric revenues derived from rate increases, as presented in the table above, include approximately $8.1 million in 1988 and $13.7 million in 1987 which represent the Nine Mile Two in-service revenue requirements estimated in the Company's rate proceedings. Since commercial operation of Nine Mile Two was delayed beyond the date assumed in those rate orders, these revenues were deferred through a debit (charge) to operating expenses and, therefore, did not affect earnings. With the commercial operation of Nine Mile Two, the Company began to reverse these deferrals, as discussed under the heading Operating Expenses, Excluding Fuel.

Beginning in July 1988 as part of a rate decision, the PSC approved recording of unbilled revenue. Accordingly, approximately $42 million associated with the change in accounting will be amortized to income during the period July 1988 to July 1990. Unbilled revenues represent revenues for energy delivered to customers, but not yet recorded as income. As a non-cash item, such revenues do not enhance the Company's cash position. The Company has recorded unbilled accounts receivable of $45.9 million as of December 31, 1988. In accordance with the 1988 Rate Agreement, $8.5 million of unbilled revenue was recognized in the Company's 1988 Statement of Income. The deferred credit balance ($39.8 million at December 31, 1988) will be amortized monthly to revenues in accordance with PSC rate decisions. Under the 1988 Rate Agreement, the Company will amortize to revenues $20.6 million of these deferred unbilled revenues in 1989. Recognition of unbilled revenue will affect the Company's normal seasonal earnings pattern beginning in 1989, since the recognition of revenues, primarily for the Gas Department, will occur in different months than in the past. Accordingly, beginning with 1989, fourth quarter earnings will be higher and first quarter earnings will be lower than in prior years.

The Company's fuel clause provisions provide that customers and shareholders will share, generally on an 80%/20% basis, respectively, the risks or benefits derived from variations in electric fuel costs, generation mix and sales of electricity to other utilities compared with forecasted amounts as established by the PSC. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were reduced $1.1 million in 1988 primarily reflecting the variance between actual fuel costs and generation mix compared with rate assumptions. Earnings in 1987 were enhanced by $9.7 million on a pretax basis related to these sharing arrangements, primarily attributable to provisions effective prior to August 1987 associated with electric sales to other utilities.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from space heating customers comprise about 90 percent of total gas operating revenues. Measured on a customer billing degree day basis, the weather as related to heating in 1988 was approximately seven percent colder than 1987. Conversely, weather for all of 1987 was four and one-half percent warmer

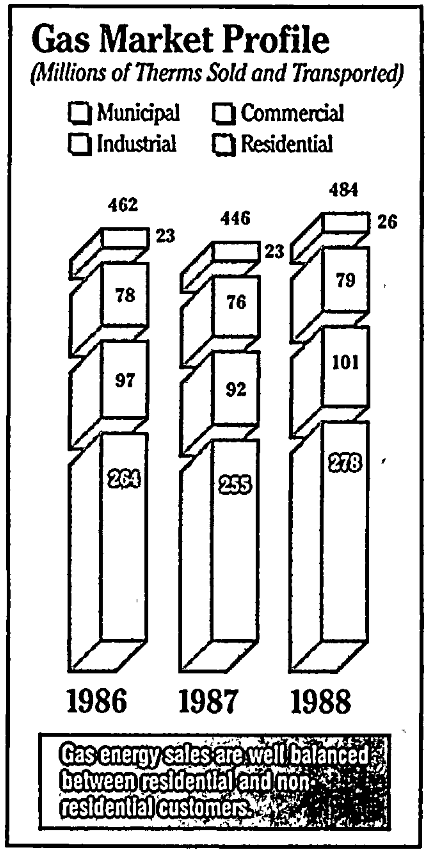


than 1986 on a customer billing degree day basis.

As illustrated by the graph above, the sale of electric energy is well diversified among all major customer classes and a strong local economy resulted in an increase of electric sales to all major customer groups in 1988 and 1987. Unusually warm weather during the summer months of 1987, followed with even warmer weather during the 1988 summer months, resulted in an increased use of air conditioning during both comparison periods. In addition, the continued strong growth in the number of electric customers contributed to increased sales of electricity in 1988 and 1987. In August 1988, the Company experienced a new record demand of 1,275 megawatts on its electric system, or 5.8 percent above the previous record peak demand set in 1987.

Fluctuations in revenues from electric sales to other utilities are generally related to the Company's customer energy requirements, New York Power Pool energy market conditions and the availability of electric generation from the Company's nuclear-fueled plants, including its share of Nine Mile Two. The availability of power from Nine Mile Two, along with generation from the Ginna nuclear plant, allows the Company to sell more fossil-fueled generation to other utilities while retaining lower-cost nuclear-generated energy for the Company's own electric customers.

Since October 1985 the Company has transported gas for certain large commercial and industrial customers (and, more recently, certain large municipal customers) who are able to purchase natural gas directly from producers and use the Company's facilities to transport it. Gas supplies transported in this manner, which amounted to 83.6 million therms in 1988 and 67.5 million therms in 1987, are not included in Company therm sales. These purchases cause decreases in customer revenues, as shown in the table on page 11, with offsetting decreases in fuel expenses, but do not adversely affect earnings because these customers are billed at rates which, except for the cost of gas, approximate the rates charged the Company's other gas service customers.



Total therms sold and transported increased in 1988 by 8.6 percent after decreasing 3.5 percent in 1987, as presented in the graph above. These fluctuations reflect the effect of weather variations, as previously discussed, primarily on therm sales to residential customers with gas space heating. In 1988, an increase in

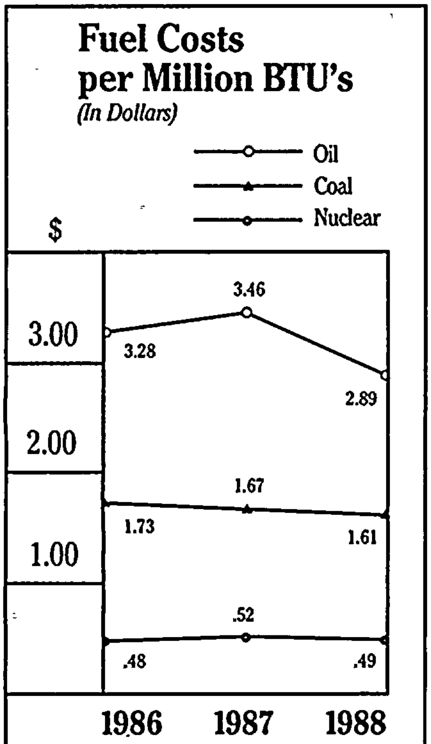
Operating Expenses

Increase or (Decrease) from Prior Year (Thousands of Dollars)	1988	1987
Fuel for Electric Generation	$ 4,344	$ 11,912
Purchased Electricity	3,832	(3,677)
Deferred Fuel—Electric	(869)	(2,806)
Gas Purchased for Resale	7,038	(39,168)
Other Operation	519	10,830
Maintenance	6,451	1,357
Depreciation and Amortization	14,173	3,458
Taxes Charged to Operating Expenses	(9,497)	(5,621)
Total Change in Operating Expenses	$25,991	$(23,715)

gas therm consumption, as adjusted for normal weather, per heating customer and continued growth in the number of gas customers in 1988 and 1987 bolstered therm sales. Also, in 1988 several major dual-fuel industrial customers consistently used gas during the year whereas in 1987 they were fully or partially burning oil.

Operating Expenses

Compared with the prior year, operating expenses increased 4.3 percent in 1988 following a 3.7 percent decrease in 1987. The 1988 increase, in part, is due to the recording of Nine Mile Two operation and maintenance expenses commencing in April 1988, as mentioned above. In 1989, pursuant to the terms of the 1988 Rate Agreement, the Company will absorb, or benefit by, the first $825,000 of any Nine Mile Two operating expense variance from a forecasted amount of $13.3 million and then share 50 percent of any remaining variance with its customers. A summary of the change in operating expenses for the 1988 and 1987 comparison periods is presented in the table on page 12.



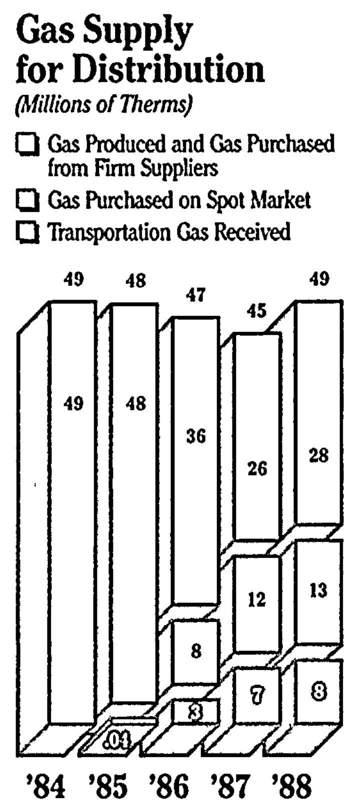
The price of nuclear fuel continues its significant advantage over the cost of fossil fuel.

Energy Costs—Electric. The increase in fuel expenses for electric generation for both comparison periods reflects increased generation from both the Company's fossil-fueled and nuclear generating units, including commercial generation from Nine Mile Two. The increase in fuel expenses, however, was relatively less than the increase in generation, reflecting largely a drop in fuel costs, as illustrated by the graph below left.

Fluctuations in purchased electricity expense resulted primarily from changes in kilowatt-hours purchased, together with increasing average rates in 1987 and 1988.

Energy Costs—Gas. The gas procurement practices of the Company reflect a more open-market approach taking place in the gas utility industry. This approach allows the Company and several of its large-consumption gas customers to take greater advantage of favorable spot market purchases, as illustrated by the graph to the upper right. These purchases, together with contract purchases, provide more flexibility while still assuring an adequate supply of gas. The variation in the cost of gas purchased reflects changes in the volume of gas purchased for the Company's customers, coupled with lower average rates for both comparison periods.

As discussed under the heading New York State Public Service Commission (PSC), the Company at December 31, 1988 had deferred $1.1 million of take-or-pay charges from gas pipeline suppliers. Disposition of such deferred charges, recorded on the Company's Balance Sheet as a deferred asset, is subject to future PSC determination.



Gas procurement by the Company and its major gas customers reflects a more open-market approach.

Operating Expenses, Excluding Fuel. Excluding accounting procedures which affect certain operating accounts, other operation expenses were unchanged in 1987 in contrast to an increase of approximately $20 million in 1988. These additional other operation expenses in 1988 include $10.7 million of expenses associated with the commercial operation of Nine Mile Two. Increasing other operation expenses in 1987 by $9.5 million was an accounting procedure in connection with the deferral of Nine Mile Two revenues (see Operating Revenues and Sales). With the commercial operation in April 1988 of Nine Mile Two, accounting adjustments were made to reverse prior revenue deferrals which had recognized recovery of Nine Mile Two operation and maintenance expenses prior to the actual commercial operation date. Such accounting adjustments reduced other operation expenses by a net amount of approximately $18 million in 1988.

≡ Higher maintenance expenses in 1988 reflect increased refueling shutdown and maintenance expenses at the Ginna nuclear plant and the recording of Nine Mile Two expenses starting in April 1988. Increased maintenance costs at the Company's fossil-fueled electric generating plants led to higher maintenance costs in 1987 compared to a year earlier.

≡ The recognition of Nine Mile Two depreciation expense, commencing with the commercial operation of the facility in April 1988, was responsible for most of the depreciation and amortization expense variance between the 1988 and 1987 comparison periods.

Taxes. Fluctuations in local, state and other taxes reflect changes in gross income and gross earnings taxes, which are based on revenues, together with the effect of higher property taxes due to higher tax rates and assessments. Over one-half of the increase in local, state and other taxes in the 1988 comparison period resulted from the recognition of these costs as operating expenses once Nine Mile Two entered commercial operation.

≡ In October 1986, the Tax Reform Act of 1986 (Tax Act) was enacted. As a result of the Tax Act, the Company's marginal Federal income tax rate was reduced from 46 percent in 1986 to 40 percent in 1987, with a further reduction to 34 percent in 1988 and thereafter. The Tax Act eliminated investment tax credits and required the inclusion of unbilled revenues in taxable income. The provisions of the Tax Act resulted in higher currently payable Federal income taxes, but a reduced total Federal income tax provision for book purposes. The 1988 Rate Agreement incorporated these tax changes through July 1990 and called for the adjustment of certain accumulated deferred tax balances to the 34 percent level over the two-year period ending July 1990, with the exception of deferred tax balances related to accelerated depreciation and Ginna nuclear plant decommissioning costs. The 1988 Rate Agreement also provided for deferred accounting of any statutory increases or decreases in federal or state taxes which have an impact of $1 million or more on the Company's tax expense and occur subsequent to July 31, 1989. Such deferred balances will be preserved for disposition in the Company's next rate proceeding.

≡ In December 1987, the FASB issued a Statement of Financial Accounting Standards entitled "Accounting for Income Taxes" (SFAS-96). Among other things, SFAS-96 requires the Company to adjust certain of its deferred tax assets and liabilities to reflect periodic changes in tax rates. In addition, the Company may also be required to provide deferred taxes for the effect of tax benefits previously flowed through to the Income Statement. SFAS-96 is not required to be adopted by the Company until the first quarter of 1990. The Company is presently unable to estimate the effects of the adoption of SFAS-96, but absent additional changes in the Federal tax code and as the result of certain tax-related provisions contained in the 1988 Rate Agreement (see previous paragraph), the Company does not believe the earnings impact to be significant.

Other Statement of Income Items

As discussed above, the Company's 1987 Statement of Income reflects the cumulative effect as of January 1, 1987 of an accounting change in connection with the write-off of disallowed Nine Mile Two plant costs in 1987. Disallowed costs for the period subsequent to January 1, 1987 are reported under the caption "Other Income and Deductions" on the Statement of Income.

≡ AFUDC variances are generally related to the amount of utility plant under construction not included in rate base. AFUDC was not recognized on disallowed Nine Mile Two plant costs; and, for 1988 and 1987, the amount of AFUDC reported reflects such disallowance. AFUDC reported in prior years has not been restated for such disallowed costs as a result of the accounting change adopted by the Company and referenced above. Compared to 1987, the lower level of AFUDC for 1988 resulted primarily from the transfer of Nine Mile Two utility plant under construction not included in rate base to plant-in-service in April 1988.

≡ Other Income includes $6.4 million of non-cash earnings in 1987 and $4.5 million in 1986 associated with the amortization of certain customer prepaid Nine Mile Two financing costs which had been deferred, as discussed under the heading New York State Public Service Commission (PSC). Other Income in 1988 resulted mainly from interest income on temporary cash investments.

≡ Despite the issuance of additional long-term debt over the three-year period 1986–1988, long-term debt interest expense during this period declined primarily as a result of the Company's optional redemptions of certain high-cost first mortgage bonds.

Earnings/Summary

Presented on page 15 is a table which summarizes the Company's common earnings in total and on a per-share basis as reported and as modified to exclude disallowed Nine Mile Two costs written off in 1987 and to exclude AFUDC on these costs in

1987 and 1986. AFUDC as a percentage of such modified common earnings is presented in the graph below. No additional Nine Mile Two plant costs were written off in 1988. As discussed under the heading Nine Mile Two, future adjustment to the 1987 write-off may be recognized by the Company upon recognition by the PSC of a definitive commercial operation date for Nine Mile Two and the resolution of certain issues being disputed with the PSC regarding the implementation of the Nine Mile Two Settlement (see Note 10 of the Notes to Financial Statements).

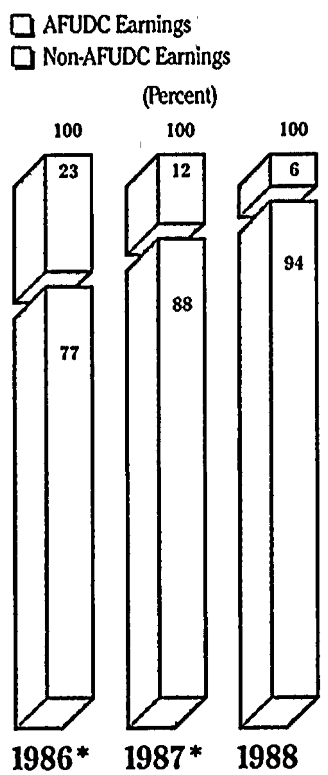
In September 1987 the Company announced a reduction in its quarterly dividend rate from $.55 per share to $.375 per share, or $1.50 on an annual basis. This adjusted dividend rate, which has been paid quarterly since the fourth quarter of 1987, resulted from the Company's analysis of the PSC's 1987 rate decision which indicated that anticipated earnings were not expected to cover Common Stock dividends at the former rate. Although the Company believes that the current annual Common Stock dividend rate of $1.50 per share is sustainable, its ability to maintain the Common Stock dividend level and its Preferred Stock dividend is necessarily dependent on future earnings, which the Company cannot predict. The Company's Charter provides for the payment of dividends on Preferred Stock and Common Stock out of the surplus net profits (retained earnings) of the Company. The Company would not be able to pay Preferred or Common Stock dividends unless positive retained earnings were maintained. As of December 31, 1988 the Company's retained earnings were approximately $39.7 million. The Company presently intends to establish a retained earnings base at least equal to its annual dividend requirement for both preferred and common stocks before considering an increase in the Common Stock dividend rate above the annual rate of $1.50 per share.

Earnings Summary

	Earnings (Thousands of Dollars)	Shares[1] (Thousands)	Earnings per Share
1988			
As Reported	$ 68,766	30,513	$ 2.25
1987			
As Reported	$(176,858)	29,728	$(5.95)
Excluding Nine Mile Two Write-Off	$ 63,042[2]	29,728	$ 2.12
1986			
As Reported	$ 96,461	28,927	$ 3.33
Excluding Nine Mile Two Write-Off	$ 67,161[2]	28,927	$ 2.32

[1]*Weighted average shares outstanding.*
[2]*Reported earnings modified to exclude disallowed Nine Mile Two costs written off in 1987 and to exclude AFUDC on these costs in 1987 and 1986. See Note 10 of the Notes to Financial Statements.*

AFUDC as a Percent of Earnings



*Earnings modified to exclude disallowed Nine Mile Two costs written off in 1987 and to exclude AFUDC on these costs in 1986 and 1987.

The quality of earnings is improved with a lower level of AFUDC earnings.

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Statement of Income

(Thousands of Dollars)	Year Ended December 31	1988	1987	1986
Operating Revenues	Electric	$513,617	$ 489,215	$466,496
	Gas	230,395	216,058	261,688
		744,012	705,273	728,184
	Electric sales to other utilities	29,966	26,215	20,465
	Total Operating Revenues	773,978	731,488	748,649
Operating Expenses	Fuel Expenses			
	Fuel for electric generation	65,787	61,443	49,531
	Purchased electricity	30,299	26,467	30,144
	Electric deferred fuel	(1,020)	(151)	2,655
	Gas purchased for resale	128,774	121,736	160,904
	Total Fuel Expenses	223,840	209,495	243,234
	Operating Revenues Less Fuel Expenses	550,138	521,993	505,415
	Other Operating Expenses			
	Operations excluding fuel expenses	159,689	159,170	148,340
	Maintenance	52,575	46,124	44,767
	Depreciation and amortization	69,703	55,530	52,072
	Taxes—local, state and other	88,635	82,869	84,590
	Federal income tax	40,662	55,925	59,825
	Total Other Operating Expenses	411,264	399,618	389,594
	Operating Income	138,874	122,375	115,821
Other Income and Deductions	Allowance for other funds used during construction	2,047	5,030	32,828
	Federal income tax	1,683	17,520	13,880
	Disallowed project costs	—	(55,860)	—
	Other, net	6,901	8,831	6,725
	Total Other Income and Deductions	10,631	(24,479)	53,433
	Income Before Interest Charges	149,505	97,896	169,254
Interest Charges	Long term debt	72,270	73,489	74,571
	Other, net	2,898	2,814	2,142
	Allowance for borrowed funds used during construction	(1,777)	(2,696)	(11,978)
	Total Interest Charges	73,391	73,607	64,735
	Income Before Cumulative Effect of Accounting Change	76,114	24,289	104,519
	Cumulative Effect for Years Prior to 1987 of Accounting Change for Disallowed Costs (less related Federal income tax benefits of $65,000)	—	(193,000)	—
	Net Income (Loss)	76,114	(168,711)	104,519
	Dividends on Preferred Stock	7,348	8,147	8,058
	Earnings (Loss) Applicable to Common Stock	$ 68,766	$(176,858)	$ 96,461
	Weighted Average Number of Shares for Period (000's)	30,513	29,728	28,927
	Earnings (Loss) per Common Share			
	—Before Cumulative Effect of Accounting Change	$2.25	$ .54	$3.33
	—Cumulative Effect of Accounting Change	—	(6.49)	—
	Total	$2.25	$(5.95)	$3.33

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Statement of Retained Earnings

(Thousands of Dollars)	Year Ended December 31	1988	1987	1986
	Balance at Beginning of Period	$ 17,617	$ 249,505	$216,795
	Add			
	Net Income (Loss)	76,114	(168,711)	104,519
	Total	93,731	80,794	321,314
	Deduct			
	Dividends declared on capital stock			
	Cumulative preferred stock	7,348	8,147	8,058
	Common stock	45,832	55,030	63,751
	Preferred stock redemption	841	—	—
	Total	54,021	63,177	71,809
	Balance at End of Period	$ 39,710	$ 17,617	$249,505

The accompanying notes are an integral part of the financial statements.

Balance Sheet

(Thousands of Dollars)	At December 31	1988	1987
Assets	**Utility Plant**		
	Electric	$1,558,001	$1,031,334
	Gas	272,377	258,828
	Common	86,523	81,637
	Nuclear fuel	206,021	188,049
		2,122,922	1,559,848
	Less: Accumulated depreciation	507,948	457,605
	Nuclear fuel amortization	145,928	129,235
		1,469,046	973,008
	Construction work in progress	41,044	501,738
	Net Utility Plant	1,510,090	1,474,746
	Current Assets		
	Cash and cash equivalents	73,031	60,146
	Accounts receivable, net of allowance for doubtful accounts: 1988—$5,526; 1987—$5,498	63,728	53,709
	Unbilled revenue receivable	45,853	—
	Receivable under Nine Mile cotenant agreement	—	40,600
	Materials and supplies, at average cost		
	Fossil fuel	8,220	9,707
	Construction and other supplies	9,178	10,544
	Prepayments	11,303	9,603
	Total Current Assets	211,313	184,309
	Deferred Debits		
	Sterling project property loss	10,537	19,052
	Unamortized debt expense	13,072	14,678
	Deferred finance charges—Nine Mile project	44,656	73,631
	Other	33,750	24,165
	Total Deferred Debits	102,015	131,526
	Total Assets	$1,823,418	$1,790,581
Capitalization and Liabilities	**Capitalization**		
	Long term debt—mortgage bonds	$ 651,076	$ 703,426
	—promissory notes	141,900	141,900
	Preferred stock redeemable at option of Company	67,000	67,000
	Preferred stock subject to mandatory redemption	30,000	50,797
	Common shareholders' equity		
	Common stock	504,907	494,018
	Retained earnings	39,710	17,617
	Total Common Shareholders' Equity	544,617	511,635
	Total Capitalization	1,434,593	1,474,758
	Long Term Liability—Department of Energy	51,016	47,773
	Current Liabilities		
	Long term debt due within one year	34,750	2,750
	Preferred stock redeemable within one year	—	812
	Accounts payable	37,031	32,833
	Dividends payable	13,054	13,297
	Taxes accrued	5,992	3,423
	Interest accrued	15,652	15,922
	Pension costs accrued	1,885	1,359
	Other	17,869	20,108
	Total Current Liabilities	126,233	90,504
	Deferred Credits and Other Liabilities		
	Accumulated deferred income taxes	117,345	86,884
	Deferred unbilled revenue	39,780	—
	Deferred finance charges—Nine Mile project	44,656	73,631
	Other	9,795	17,031
	Total Deferred Credits and Other Liabilities	211,576	177,546
	Commitments and Other Matters *(Notes 10 and 11)*		
	Total Capitalization and Liabilities	$1,823,418	$1,790,581

The accompanying notes are an integral part of the financial statements.

Statement of Cash Flows

(Thousands of Dollars)	Year Ended December 31	1988	1987	1986
Cash Flow from Operations	**Net income (loss)**	$ 76,114	$(168,711)	$ 104,519
	Adjustments to reconcile net income to net cash provided from operating activities:			
	Depreciation and amortization	69,703	55,530	52,072
	Amortization of nuclear fuel	19,945	20,678	18,598
	Deferred fuel—electric	(1,020)	(151)	2,655
	Deferred income taxes, net	28,124	4,984	22,810
	Allowance for funds used during construction	(3,824)	(7,726)	(44,806)
	Disallowed project costs—Nine Mile plant	—	248,860	—
	Unbilled revenue, net	(8,528)	—	—
	Changes in certain current assets and liabilities:			
	Accounts receivable	(10,019)	746	12,037
	Receivable under Nine Mile côtenant agreement	40,600	—	(40,600)
	Materials and supplies—fossil fuel	1,487	3,444	(1,438)
	—construction and other supplies	1,366	527	(1,770)
	Taxes accrued	2,569	7,105	(4,981)
	Accounts payable	4,724	5,014	(17,669)
	Interest accrued	(270)	1,686	(349)
	Other current assets and liabilities, net	(3,928)	5,891	2,694
	Other, net	(6,644)	(4,972)	(3,021)
	Total Operating	$ 210,399	$ 172,905	$ 100,751
Cash Flow from Investing Activities	**Utility Plant**			
	Plant additions	$ (96,439)	$(110,139)	$(194,315)
	Receivable under Nine Mile cotenant agreement	—	—	40,600
	Nuclear fuel additions	(17,972)	(18,552)	(14,893)
	Less: Allowance for funds used during construction	3,824	7,726	44,806
	Additions to Utility Plant	(110,587)	(120,965)	(123,802)
	Sterling project property loss	(95)	17,023	—
	Other, net	(1,056)	(436)	(548)
	Total Investing	$(111,738)	$(104,378)	$(124,350)
Cash Flow from Financing Activities	**Proceeds from:**			
	Sale of common stock	$ 11,189	$ 16,268	$ 18,827
	Sale of preferred stock	—	30,000	—
	Sale of long term debt, mortgage bonds	25,500	75,000	75,000
	Sale of long term debt, promissory notes	—	50,000	—
	Net borrowings (repayments) under:			
	Short term debt, net	—	(18,000)	18,000
	Retirements of:			
	Preferred stock	(22,758)	(23,462)	(2,472)
	Long term debt	(45,833)	(67,750)	(52,750)
	Capital stock expense	8	(1,993)	(166)
	Discount and expense of issuing long term debt	(496)	(4,476)	(3,729)
	Dividends paid on preferred and common stock	(53,423)	(67,949)	(71,459)
	Other, net	37	203	86
	Total Financing	$ (85,776)	$ (12,159)	$ (18,663)
	Increase (decrease) in cash and cash equivalents	$ 12,885	$ 56,368	$ (42,262)
	Cash and cash equivalents at beginning of year	$ 60,146	$ 3,778	$ 46,040
	Cash and cash equivalents at end of year	$ 73,031	$ 60,146	$ 3,778

Supplemental Disclosure of Cash Flow Information

	Year Ended December 31	1988	1987	1986
Cash Paid During the Year	**Interest paid (net of capitalized amount)**	$ 71,124	$ 62,175	$ 63,485
	Income taxes paid	$ 10,521	$ 22,404	$ 28,998

The accompanying notes are an integral part of the financial statements.

Notes to Financial Statements

Note 1. Summary of Accounting Policies

General. The Company is subject to regulation by the Public Service Commission of the State of New York (PSC) under New York statutes and by the Federal Energy Regulatory Commission (FERC) as a licensee and public utility under the Federal Power Act. The Company's accounting policies conform to generally accepted accounting principles as applied to New York State public utilities giving effect to the rate-making and accounting practices and policies of the PSC.

In December 1986, the Financial Accounting Standards Board (FASB) issued its Statement of Financial Accounting Standards No. 90 (SFAS-90) with respect to, among other things, the financial accounting for disallowed costs of recently completed plants. Under SFAS-90, a loss must be recognized when it becomes probable that some portion of the costs of the plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made. SFAS-90 is generally effective beginning in 1988 with earlier application encouraged, but applies to plant costs disallowed prior thereto. The Company elected to adopt SFAS-90 in the third quarter of 1987 for its investment in Nine Mile Point Nuclear Plant Unit No. 2 (Unit 2).

In adopting SFAS-90, the Company presented the cumulative effect of the accounting change prior to January 1, 1987 in the Statement of Income rather than restate previously issued financial statements. Refer to Note 10 for additional information.

In November 1987, the FASB issued SFAS-95, which established a Statement of Cash Flows that replaced the Statement of Changes in Financial Position. This new standard was adopted by the Company in 1988. For comparative purposes, the Company has retroactively applied the provisions of SFAS-95 to 1987 and 1986. For purposes of this statement, the Company considers cash equivalents to be short-term investments of three months or less.

In June 1988, the Board of Directors authorized the creation of Utilicom, Inc. as a wholly owned subsidiary. Utilicom develops and markets computer software to assist customers in complying with state and federal environmental and safety regulations. Authorization from the PSC is pending and the subsidiary activity has to date been insignificant.

A description of the Company's principal accounting policies follows.

Rates and Revenue. Revenue in 1987 and 1986 was recorded on the basis of meters read during the calendar year. In addition, beginning in July 1988, as part of a rate decision, the PSC approved recording of unbilled revenue. Accordingly, approximately $42 million associated with the change in accounting will be amortized to income during the period July 1988 to July 1990. Unbilled revenue recognizes service rendered subsequent to the meter read date but prior to the end of the accounting period. In connection with the change in accounting, approximately $7.2 million and $1.3 million have been recognized in the Statement of Income in 1988 for electric and gas, respectively.

Tariffs for electric and gas service include fuel cost adjustment clauses which adjust the rates monthly to reflect changes in the actual average cost of fuels. The electric fuel adjustment provides that ratepayers and the Company will share the effects of any variation from forecast monthly unit fuel costs on an 80%/20% basis up to a $2.6 million cumulative, after tax, annual gain or loss to the Company. Thereafter, 100 percent of additional fuel clause adjustment amounts are assigned to ratepayers. There is also an 80%/20% sharing of variances in gains or losses from PSC established forecast amounts related to margins on electricity sales to other electric utilities. In addition, there is a similar 80%/20% sharing process of variances from forecasted revenues derived from sales to large gas customers that can use alternate fuels. This process limits any loss to the Company to $1 million pretax per year if these customers utilize their alternative fuels.

The gas department tariffs provide a separate but equivalent rate, excluding the cost of gas, to reflect charges for the transportation of privately owned gas through the Company's facilities.

Deferred Fuel Costs. Fuel costs which are recoverable under the electric and gas cost adjustment clauses included in the tariff schedules of the Company are deferred until they are billed to customers. A reconciliation of recoverable gas costs with gas revenues is done annually as of August 31, and the excess or deficiency is refunded to or recovered from the customers during a subsequent twelve-month period.

Utility Plant, Depreciation and Amortization. The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect

(Note 1 continued on page 20)

(Continued from page 19)

charges such as engineering and supervision, and is recorded at original cost. See Note 10 for discussion of Unit 2. The Company capitalizes an allowance for funds used during construction approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. Replacement of minor items of property is included in maintenance expenses. Costs of depreciable units of plant retired are eliminated from utility plant accounts, and such costs, plus removal expenses, less salvage, are charged to accumulated depreciation and amortization.

Depreciation in the financial statements is provided on a straight-line basis at rates based on the estimated useful lives of property, which have resulted in provisions of 3.6% per annum of average depreciable property in each of the last three years. Amortization includes $8.6 million in 1988, $6.5 million in 1987 and $5.5 million in 1986 related to the Sterling project property loss.

Nuclear Fuel Disposal Costs. The Nuclear Waste Policy Act (Act) of 1982, as amended, requires the United States Department of Energy (DOE) to establish a nuclear waste disposal site by 1998 and to take title to nuclear waste. The Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be approximately $51.0 million at December 31, 1988. The Company has collected in rates an amount sufficient for the disposal of nuclear fuel irradiated prior to April 7, 1983. The estimated fees are classified as a long-term liability and interest is accrued on a quarterly basis. The Act also provides for the disposal of nuclear fuel irradiated after April 6, 1983, in exchange for a charge of one mill ($.001) per KWH generated at nuclear plants. This charge is currently being collected from customers and paid to the DOE pursuant to PSC authorization.

Nuclear Decommissioning Costs. Decommissioning costs (costs to take the plant out of service in the future) for the Company's Ginna Nuclear Plant are estimated by the PSC to be approximately $179.1 million in the year 2006 when the permanent license expires, and the Company's share of Unit 2's decommissioning costs are estimated to be approximately $135.4 million at license expiration in the year 2026. Through December 31, 1988, the Company has accrued and recovered in rates $22.1 million for this purpose and is currently accruing additions to a reserve at a rate of approximately $3.5 million per year based on a graduated revenue requirement methodology adopted by the PSC. (See Note 11.)

Allowance for Funds Used During Construction. The Company capitalizes an Allowance for Funds Used During Construction (AFUDC) based upon the net cost of borrowed funds for construction purposes, and a reasonable rate upon the Company's other funds when so used. In accordance with an order issued by the FERC, AFUDC is segregated into two components and classified in the Statement of Income as Allowance for Borrowed Funds Used During Construction, an offset to Interest Charges, and Allowance for Other Funds Used During Construction, a part of Other Income.

Effective July 16, 1984, pursuant to PSC authorization, the Company discontinued accruing AFUDC on $50 million of construction work in progress related to its investment in Unit 2 for which a cash return was being allowed through its inclusion in rate base. An additional $150 million and $230 millon were included in rate base, effective July 9, 1985 and July 14, 1986, respectively, as authorized by the PSC, and AFUDC accruals were likewise discontinued. The PSC also ordered in 1984 that amounts be accumulated in deferred debit and credit accounts equal to the amount of AFUDC which was no longer accrued. The balance in the deferred credit account would be available to reduce future revenue requirements over a period substantially shorter than the life of Unit 2 and the balance in the deferred debit account would then be collected from customers over a longer period of time. In July 1988, in accordance with PSC Opinion 88-21, the Company eliminated by offset one-half of the deferred debit and credit balances in connection with the unused portion of customer prepaid financing costs associated with Unit 2 (See Note 10), reducing the cumulative balance to $44.7 million. In accordance with PSC Opinion 86-17, issued July 14, 1986, $10.875 million of these accruals were amortized over the rate year commencing August 1, 1986. The deferred credit was discharged through the Income Statement in 1986 and

1987, while the deferred debit was reclassified into a separate deferred debit account. In connection with the Company's current rate settlement, approximately $4 million will be amortized through the income statement commencing August 1, 1989.

In September 1987, the Company wrote off $22.1 million in AFUDC that had been recorded in 1987 applicable to PSC disallowed expenditures in Unit 2.

The gross rates approved by the PSC for purposes of computing AFUDC were: 10.25% effective January 1, 1988; 10.20% effective August 1, 1987 through December 31, 1987; 10.60% effective August 1, 1986 through July 31, 1987; and 12.00% effective for the seven months ended July 31, 1986. AFUDC on certain major construction projects, however, including Unit 2, has been applied at a reduced rate which is net of the income tax effect of the interest portion of AFUDC. The net-of-tax rates used on these projects for 1988, 1987 and 1986 were 8.55%, 8.47% and 9.32%, respectively.

Federal Income Tax. For income tax purposes, depreciation is computed using the most liberal methods permitted. In addition, certain costs capitalized for financial reporting purposes were deducted currently for income tax purposes in accordance with the Internal Revenue Code prior to the enactment of the Tax Reduction Act of 1986. The resulting tax reductions were offset by provisions for deferred income taxes only to the extent ordered or permitted by regulatory authorities. The cumulative balance of tax deductions not offset by provisions for deferred income taxes through 1988 is approximately $395 million.

The Company provides for full normalization of depreciation and investment tax credits. The Tax Reform Act of 1986 provided for the repeal of investment tax credits; however, some credits continue to be available under the transitional rules contained in the Tax Act.

The Company uses the separate-period approach in calculating the interim quarterly tax provision.

SFAS-96, Accounting for Income Taxes (as amended by SFAS-100), was issued in December of 1987 and has not yet been adopted by the Company. SFAS-96 requires adoption in calendar year 1990 and that a deferred tax liability or asset be adjusted in the period of enactment for the effect of changes in tax laws or rates. Additionally, the Company may also be required to provide deferred taxes for the effect of taxes previously flowed through the Income Statement. The Company is presently unable to estimate the effects of the adoption of SFAS-96, but absent additional changes in the Federal tax code, the Company does not believe the earnings impact to be significant.

Retirement Health Care and Life Insurance Benefits. The Company provides certain health care and life insurance benefits for retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. These and similar benefits for active employees are provided through insurance companies whose premiums are based upon the experience of benefits actually paid. The Company recognizes the costs of providing these benefits by a current charge to expense. The cost of providing these benefits was approximately $1.8 million in 1988, $1.8 million in 1987 and $1.6 million in 1986.

Earnings and Dividends Per Share. Earnings applicable to each share of common stock are based on the weighted average number of shares outstanding during the respective years. The pro forma earnings (loss) per share, assuming the accounting change described above and in Note 10 was applied retroactively, are $.54 in 1987 and $(3.33) in 1986.

Notes to Financial Statements

Note 2. Federal Income Taxes *(Thousands of Dollars)*

The provision for Federal income taxes is distributed between operating expense and other income based upon the treatment of the various components of the provision in the rate-making process. The following is a summary of income tax expense for the three most recent years.

	1988	1987	1986
Charged to operating expense:			
Current	$20,363	$ 32,781	$ 22,521
Deferred	20,299	23,144	37,304
Total	40,662	55,925	59,825
Charged (Credited) to other income:			
Current	(9,508)	640	614
Deferred	7,825	(18,160)	(14,494)
Total	(1,683)	(17,520)	(13,880)
Total Federal income tax expense	$38,979	$ 38,405	$ 45,945

The following is a reconciliation of the difference between the amount of Federal income tax expense reported in the Statement of Income and the amount computed by multiplying the income by the statutory tax rate.

	1988		1987		1986	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Income before cumulative effect of accounting change	$ 76,114		$24,289		$104,519	
Add: Federal income tax expense	38,979		38,405		45,945	
Income before Federal income tax	$115,093		$62,694		$150,464	
Computed tax expense	$ 39,132	34.0	$25,078	40.0	$ 69,213	46.0
Increases (decreases) in tax resulting from:						
Expenses capitalized for financial reporting purposes	—		(8,337)	(13.3)	(23,168)	(15.4)
Disallowed project costs	—		15,064	24.0	—	
Difference between tax depreciation and amount deferred	1,626	1.4	4,312	6.9	3,885	2.6
Investment tax credit	(3,763)	(3.2)	(3,701)	(5.9)	(5,177)	(3.4)
Tax Reduction Act benefits deferred	—		4,561	7.3	—	
Miscellaneous items, net	1,984	1.7	1,428	2.3	1,192	.7
Total Federal income tax expense	$ 38,979	33.9	$38,405	61.3	$ 45,945	30.5

A summary of the deferred amounts charged or (credited) to income is as follows:

	1988	1987	1986
Investment tax credit	$ (3,763)	$ (4,619)	$10,145
Depreciation	29,519	26,956	12,855
Fuel costs	2,681	1,086	(5,035)
Sterling abandonment	585	(8,249)	(1,597)
Capitalized overheads	(265)	3,410	4,278
Accrued revenue	(442)	(4,740)	—
Disallowed project costs	—	(8,960)	—
Other items	(191)	100	2,164
Total	$28,124	$ 4,984	$22,810

Note 3. Pension Plan

The Company has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service and the employee's compensation during the last three years of employment. The Company's funding policy is to contribute annually an amount consistent with the requirements of the Employee Retirement Income Security Act. These contributions are intended to provide for benefits attributed to service to date and for those expected to be earned in the future.

The plan's funded status and amounts recognized on the Company's Balance Sheet are as follows:

	(Millions)	
	1988	1987
Accumulated benefit obligation, including vested benefits of $179.1 in 1988 and $180.2 in 1987	$191.3*	$193.3*
Projected benefit obligation for service rendered to date	$276.4*	$285.0*
Less—Plan assets at fair value, primarily listed stocks and bonds	303.8	276.9
	(27.4)	8.1
Unrecognized net gain or (loss) from past experience different from that assumed and effects of changes in assumptions	36.4	(1.5)
Less—Prior service cost not yet recognized in net periodic pension cost	.1	—
Less—Unrecognized net obligation at December 31	7.0	5.3
Prepaid pension cost (pension liability) recognized on the balance sheet	$ (1.9)	$ (1.3)

**Actuarial present value*

Net pension cost included the following components:

	(Millions)	
	1988	1987
Service cost—benefits earned during the period	$ 6.9	$ 7.2
Interest cost on projected benefit obligation	22.5	20.4
Actual return on plan assets	(31.0)	(18.2)
Net amortization and deferral	12.4	1.3
Net periodic pension cost	$ 10.8	$ 10.7

The projected benefit obligation at December 31, 1988 and 1987 assumed discount rates of 8½ percent and 8 percent, respectively, and a long-term rate of increase in future compensation levels of 7 percent. The assumed long-term rate of return on plan assets was 8 percent. The unrecognized net obligation is being amortized over 15 years beginning January 1, 1986.

Pension cost for 1988, 1987, and 1986 was $10.8 million, $10.7 million, and $10.0 million, respectively. The PSC has directed the Company to defer for future disposition any differences resulting from the calculation of pension cost pursuant to SFAS-87.

Note 4. Departmental Financial Information

The Company's records are maintained by operating departments, in accordance with PSC accounting policies, giving effect to the rate-making process. The following is the operating data for each of the Company's departments, and no interdepartmental adjustments are required to arrive at the operating data included in the Statement of Income.

		(Thousands of Dollars)		
		1988	1987	1986
Electric	**Operating information**			
	Operating revenues	$ 543,583	$ 515,430	$ 486,961
	Operating expenses, excluding provision for income taxes	390,867	360,000	337,467
	Pretax operating income	152,716	155,430	149,494
	Provision for income taxes	34,093	48,788	52,051
	Net operating income	$ 118,623	$ 106,642	$ 97,443
	Other information			
	Depreciation and amortization	$ 60,444	$ 46,776	$ 43,753
	Nuclear fuel amortization	$ 19,945	$ 20,678	$ 18,598
	Capital expenditures	$ 91,941	$ 104,295	$ 108,095
	Investment information			
	Identifiable assets (a)	$1,469,571	$1,483,860	$1,729,194
Gas	**Operating information**			
	Operating revenues	$ 230,395	$ 216,058	$ 261,688
	Operating expenses, excluding provision for income taxes	203,575	193,188	235,536
	Pretax operating income	26,820	22,870	26,152
	Provision for income taxes	6,569	7,137	7,774
	Net operating income	$ 20,251	$ 15,733	$ 18,378
	Other information			
	Depreciation and amortization	$ 9,259	$ 8,754	$ 8,319
	Capital expenditures	$ 18,646	$ 16,670	$ 15,707
	Investment information			
	Identifiable assets (a)	$ 257,200	$ 224,391	$ 219,716

(a) Excludes cash, unamortized debt expense and other common items.

Note 5. Jointly-Owned Facilities

The following table sets forth the jointly-owned electric generating facilities in which the Company is participating. Both Oswego Fossil Unit No. 6 and Nine Mile Point Nuclear Plant Unit No. 2 have been constructed and are operated by Niagara Mohawk Power Corporation. Each participant must provide its own financing for any additions to the facilities. The Company's share of direct expenses associated with these two units is included in the appropriate operating expenses in the Statement of Income. Allowance for funds used during construction have been excluded from the construction costs presented below. Various modifications will be made throughout the lives of these plants to increase operating efficiency or reliability, and to satisfy changing environmental and safety regulations.

	Oswego Fossil Unit #6	Nine Mile Point Nuclear Unit #2
Net megawatt capacity	850	1,080
RG&E's share—megawatts	204	151
—percent	24	14
Year of completion	1980	1988
	(Millions of Dollars)	
Total estimated project costs		$4,214.0
RG&E's share		591.0
RG&E's actual construction costs		
—1987	$ 0.7	$ 36.0
—1988	0.6	12.2
Expended by RG&E in prior years	76.7	539.8
	$78.0	$588.0

For further information regarding Nine Mile Point Nuclear Plant Unit No. 2 refer to Note 10. Pursuant to Statement of Financial Accounting Standards No. 90, the Company, during 1987, completed a write-off in recognition of a regulatory disallowance of a portion of the Nine Mile Nuclear Plant Unit No. 2 facility for rate-making purposes. The disallowance is not included in this table. Niagara Mohawk Power Corporation estimated total project cost, including allowance for funds used during construction and prepaid financing costs, which are excluded from the table above, to be $6,533.0 million. Also not included are Company costs for initial fuel loading ($13.0 million), common facilities ($20.0 million), operating spare parts, transmission facilities, post-in-service additions, and Company direct costs.

Note 6. Long Term Debt

Mortgage Bonds

%	Series	Due	(Thousands) Principal Amount December 31 1988	1987
First Mortgage Bonds				
5	S	Oct. 15, 1989	$ 12,000	$ 12,000
4½	T	Nov. 15, 1991	15,000	15,000
4⅝	U	Sept. 15, 1994	16,000	16,000
5.3	V	May 1, 1996	18,000	18,000
6¼	W	Sept. 15, 1997	20,000	20,000
6.7	X	July 1, 1998	30,000	30,000
8	Y	Aug. 15, 1999	30,000	30,000
9⅛	Z	Sept. 1, 2000	30,000	30,000
9¼	BB	June 15, 2006	50,000	50,000
8⅜	CC	Sept. 15, 2007	50,000	50,000
9½	DD	Dec. 1, 2003	40,000	40,000
6½	EE	Aug. 1, 2009	10,000	10,000
10.95	FF	Feb. 15, 2005	44,000	49,500
12¼	HH	May 15, 2012	10,500	10,500
13⅞	JJ	June 15, 1999	25,000	25,000
11¼	KK	May 15, 1995	49,667	50,000
8.6	LL	Aug. 1, 1993	75,000	75,000
8⅞	MM	May 1, 1992	75,000	75,000
11¾	NN	June 15, 1993	60,000	
8⅜	OO	Dec. 1, 2028	25,500	
Second Mortgage Bonds				
11¾	A	June 15, 1993		100,000
			685,667	706,000
Net bond premium (discount)			159	176
Less: Due within one year			34,750	2,750
Total Long Term Debt			$651,076	$703,426

The First Mortgage provides security for the bonds through a first lien on substantially all the property owned by the Company (except cash and accounts receivable).

Sinking and improvement fund requirements aggregate $333,540 per annum under the First Mortgage, excluding mandatory sinking funds of individual series. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1987 requirement was met by certification of additional property. The 1988 requirement was met with funds deposited with the Trustee, and these funds were used for redemption of outstanding bonds of Series KK.

The Series EE, Series HH and Series OO First Mortgage Bonds equal the principal amount of and provide for all payments of principal, premium and interest corresponding to the Pollution Control Revenue Bonds,

(Note 6 continued on page 26)

(Continued from page 25)

Notes to Financial Statements

Series A, Series B and Series C, respectively (Rochester Gas and Electric Corporation Projects) issued by the New York State Energy Research and Development Authority through a participation agreement with the Company. The Series EE bonds are subject to a mandatory sinking fund beginning August 1, 2000 and each August 1 thereafter. Nine annual deposits aggregating $3.2 million will be made to the sinking fund, with the balance of $6.8 million principal amount of the bonds becoming due August 1, 2009.

The Series FF First Mortgage Bonds are subject to a mandatory sinking fund of $2.75 million annually which began on February 15, 1986 and will continue each February 15, with the noncumulative option to double the payment in any year up to a maximum of 5 years. In February 1988 and 1989, the Company exercised this option and redeemed an additional $2.75 million of Series FF Bonds in each year.

The Series JJ First Mortgage Bonds are subject to a mandatory sinking fund of $2.5 million annually beginning June 15, 1990 and each June 15 thereafter.

The Series LL and MM First Mortgage Bonds are not redeemable prior to maturity.

In January 1988 the Company redeemed the Series A Second Mortgage Bonds and exchanged them for Series NN First Mortgage Bonds. All terms and conditions of the Series NN Bonds are substantially identical to the redeemed Series A Bonds. The Series NN First Mortgage Bonds are subject to a mandatory sinking fund of $20.0 million annually beginning June 15, 1989 and each June 15 thereafter. On November 1, 1988 the Company exercised its option to redeem $40 million principal amount of these bonds at a price of 105.22%.

The bonds maturing in the next five years are $12 million in 1989 for Series S, $15 million in 1991 for Series T, $20 million in 1991 for Series NN, $75 million in 1992 for Series MM, and $75 million in 1993 for Series LL.

The sinking fund requirements for the next five years are:

	(Thousands)				
	1989	1990	1991	1992	1993
Series NN	$20,000	$20,000	$20,000		
Series FF	2,750	2,750	2,750	$2,750	$2,750
Series JJ		2,500	2,500	2,500	2,500
	$22,750	$25,250	$25,250	$5,250	$5,250

Promissory Notes

		(Thousands)	
		December 31	
Issued	Due	1988	1987
November 15, 1984	October 1, 2014	$ 51,700	$ 51,700
December 5, 1985	November 15, 2015	40,200	40,200
July 22, 1987	July 15, 2027	50,000	50,000
Total		$141,900	$141,900

The Company is obligated to make payments of principal, premium and interest on each Promissory Note which correspond to the payments of principal, premium, if any, and interest on certain Pollution Control Revenue Bonds issued by the New York State Energy Research and Development Authority (NYSERDA) as described below. These obligations under each note shall be deemed satisfied to the extent of funds drawn under certain Letters of Credit discussed below. Any amounts advanced under such Letters of Credit must be repaid, with interest, by the Company.

The $51.7 million Promissory Note was issued in connection with NYSERDA's Floating Rate Monthly Demand Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1984. This obligation shall be deemed satisfied to the extent of the funds, if any, drawn on or before October 15, 1994 under an irrevocable Letter of Credit issued by Irving Trust Company. The interest rate on this note for each monthly interest payment period will be based on the evaluation of the yields of short term tax-exempt securities at par having the same credit rating as said Series 1984 Bonds. The average interest rate was 5.22% for 1988, 5.04% for 1987 and 5.08% for 1986.

The $40.2 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1985. This obligation shall be deemed satisfied to the extent of funds, if any, drawn on or before November 30, 1990 under an irrevocable Letter of Credit issued by Westpac Banking Corporation. This Promissory Note bore interest at 6½% per annum through November 14, 1988. The interest rate was adjusted to 5.90% effective November 15, 1988 through November 14, 1989 and will continue to be adjusted annually.

The $50.0 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1987. This obligation shall be deemed satisfied to the extent of funds, if any, drawn on or before July 31, 1992 under an irrevocable Letter of Credit issued by Citibank, N.A. This Promissory Note will bear interest at 5⅞% per annum through July 14, 1990. Thereafter, the interest rate will be adjusted annually.

Note 7. Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	970,000*
Preferred Stock (cumulative)	25	4,000,000	
Preference Stock	1	5,000,000	

See below for mandatory redemption requirements

≡ No shares of preferred or preference stock are reserved for employees, or for options, warrants, conversions, or other rights.

A. *Preferred Stock,* not subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1988	(Thousands) December 31 1988	1987	Redemption (per share)*
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4¾	I	60,000	6,000	6,000	101
4.10	J	50,000	5,000	5,000	102.5
4.95	K	60,000	6,000	6,000	102
4.55	M	100,000	10,000	10,000	101
7.50	N	200,000	20,000	20,000	102
Total		670,000	$67,000	$67,000	

**May be redeemed at any time at the option of the Company on 30 days minimum notice, plus accrued dividends in all cases.*

B. *Preferred Stock,* subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1988	(Thousands) December 31 1988	1987	Redemption (per share)†
8.60	P			$21,609	$105.00 Before 9/1/89
8.25	R	300,000	$30,000	30,000	108.25 Before 3/1/92
		300,000	30,000	51,609	
Less: Redeemable within 1 year				812	
Total		300,000	$30,000	$50,797	

†Thereafter at lesser rates

≡ Mandatory redemption for Preferred Stock commenced on September 1, 1984 for Series P. The Company was required to redeem 8,125 shares per year, at $100 per share, by means of a sinking fund provision, with the noncumulative option to redeem not more than 8,125 additional shares per year on the same terms. On August 10, 1988, the Company purchased in an open market transaction and subsequently cancelled 16,732 shares of Series P Preferred Stock. On September 1, 1988, the Company called for redemption and subsequently cancelled 16,250 shares of Series P Preferred Stock, which satisfied the sinking fund requirement due September 1, 1988, and exercised its option to redeem additional shares. On December 1, 1988 all outstanding shares of Series P were called for redemption and subsequently cancelled. Mandatory redemption of 60,000 shares per year commences on March 1, 1993 for Series R. In the event the Company should be in arrears in the sinking fund requirement, the Company may not redeem or pay dividends on any stock subordinate to the Preferred Stock.

Note 8. Common Stock

At December 31, 1988, there were 35,000,000 shares of $5 par value Common Stock authorized, of which 30,785,811 were outstanding. There were 472,157 shares of Common Stock reserved and unissued under the Automatic Dividend Reinvestment and Stock Purchase Plan. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. Net gains or losses resulting from the reacquisition of certain issues of Preferred Stock to satisfy sinking fund requirements (see Note 7) are shown as Reacquired Capital Stock.

Common Stock:

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1986		28,496,809	$461,078
Automatic Dividend Reinvestment and Stock Purchase Plan	22.713-28.238	669,057	16,747
ESOP*	26.200	15,267	400
Savings Plus Plan	22.499-28.810	65,954	1,680
Capital Stock Expense			(166)
Reacquired Capital Stock			(35)
Balance, December 31, 1986		29,247,087	$479,704
Automatic Dividend Reinvestment and Stock Purchase Plan	15.175-24.750	760,986	14,132
ESOP*	23.970	17,939	430
Savings Plus Plan	14.499-24.874	95,363	1,706
Capital Stock Expense			(1,993)
Reacquired Capital Stock			39
Balance, December 31, 1987		30,121,375	$494,018
Automatic Dividend Reinvestment and Stock Purchase Plan	15.963-18.013	619,172	10,440
Savings Plus Plan	16.000-17.188	45,264	749
Capital Stock Expense			8
Reacquired Capital Stock			(308)
Balance, December 31, 1988		30,785,811	$504,907

**Employee Stock Ownership Plan*

Note 9. Short Term Debt

The Company had no outstanding short term debt at December 31, 1988 or December 31, 1987 and there were no borrowings in the calendar year 1988. The weighted average interest rates for borrowings in 1987 were 6.58% for short term notes and 6.25% for commercial paper.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years. Commitment fees related to this facility amounted to $322,000 in 1988 and $341,000 in 1987.

The Company's Charter provides that unsecured debt may not exceed 15 percent of the Company's total capitalization (excluding unsecured debt). As of December 31, 1988, the Company would be able to incur $6 million of unsecured debt under this provision. In order to be able to use its revolving credit agreement, the Company has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of the Company's Charter.

Note 10. Nine Mile Point Nuclear Plant

Nine Mile Point Nuclear Plant Unit No. 2 (Unit 2), a nuclear generating unit in Oswego County, New York, with an electrical capability of 1,080 megawatts, was completed and entered commercial service in Spring 1988. Niagara Mohawk Power Corporation (Niagara) is operating Unit 2 on behalf of all owner co-tenants pursuant to a full power operating license which the Nuclear Regulatory Commission (NRC) issued on July 2, 1987 for a 40-year term beginning October 31, 1986. Under the Basic Agreement entered into in September 1975, ownership, output, and cost of the project are shared by five co-tenants: the Company (14%), Niagara (41%), Long Island Lighting Company (LILCO) (18%), New York State Electric & Gas Corporation (18%) and Central Hudson Gas & Electric Corporation (9%).

The NRC advised Niagara on December 20, 1988, following their senior managers' biannual performance review of NRC-licensed nuclear power plants, that Unit 2 now warrants close monitoring by the NRC. Plants in this category have been identified as having weaknesses that warrant increased NRC attention. This conclusion was based on an NRC assessment of Unit 2's overall performance during its first year of operation. Nine Mile Point Nuclear Plant Unit No. 1 (Unit 1), an adjoining facility entirely owned and operated by Niagara, had been categorized in June 1988 as requiring close monitoring by the NRC. In its December 1988 evaluation, the NRC indicated that increased licensee and NRC management attention is needed to ensure that performance improvement is achieved for both units.

Unit 2 underwent an outage for planned maintenance and inspection which began October 1, 1988 and was still in progress in late January 1989. Niagara advises that the outage will continue until mid-February 1989, delaying until late February the unit's return to full power. The extension of the current outage's duration, particularly in the wake of the NRC's action noted above, heightens certain regulatory uncertainties facing the Company. The NRC's monitoring of plant conditions and the progress of outage work could lead it to require—as it has elsewhere—additional commitments of time and effort that would preclude a near-term restart. In addition, the PSC has initiated proceedings to review outages which extend beyond planned duration and may consider disallowance of some or all outage-related replacement power costs. Niagara has advised the Company that it does not believe the Unit 2 outage has been imprudently extended but is unable to predict whether the PSC will institute such a proceeding. Assuming there is not a substantial further extension, the Company believes the present outage will not have a material effect on its financial condition.

With the completion of construction and commencement of commercial operation, Niagara is preparing final cost figures for Unit 2. Its most recent estimate, announced in January 1988, was $6.120 billion, excluding nuclear fuel. Adding approximately $413 million of prepaid financing charges arising from the inclusion of construction work in progress in the rate bases of certain co-tenants, that sum is equivalent to a total Unit 2 cost of $6.533 billion. The Company's estimated share of that $6.533 billion total Unit 2 cost, including its applicable share of prepaid financing costs, would be approximately $951 million ($591 million of construction costs, $258 million of Allowance for Funds Used During Construction [AFUDC] and $102 million of prepaid financing costs). At December 31, 1988, excluding the adoption of a new accounting standard for the reporting of disallowed costs of recently completed plants (discussed below), the Company had incurred construction-related costs of $929 million ($588 million of construction costs, $245 million of AFUDC and $96 million of prepaid financing costs).

Certain of those costs, however, were disallowed for ratemaking purposes. In October 1986, the PSC approved a settlement (the "Settlement") with the co-tenants of its proceeding to inquire into the prudence of costs incurred for the construction of Unit 2. The Settlement provided that, whatever the final construction cost of Unit 2, the aggregate amount allowed in the co-tenant rate bases would be $4.16 billion, reduced by prepaid financing costs. It also barred suits among the co-tenants based on Unit 2 design, engineering and construction. In order to gain its four co-tenants' concurrence to limiting the aggregate rate base allowance for Unit 2 to the $4.16 billion level, Niagara undertook to reimburse each of them for its proportionate share of the difference between that figure and one of $4.45 billion to which the PSC Staff and all co-tenants had earlier agreed. In September 1988, Niagara paid the Company $40.6 million in connection with that undertaking.

In a series of rate orders preceding commercial operation of Unit 2, the PSC permitted most of the Company's $485 million allowed investment (its 14% share of $4.16 billion, or $582 million, less prepaid financing charges estimated at $96 million) to be reflected in its rates. During 1988, the PSC fixed April 5, 1988 as the Unit 2 commercial operation date for Niagara and LILCO, but it has not yet taken formal action on the subject with respect to the rates and accounts of the Company. The Company's rate case settlement, which the PSC approved on July 20, 1988, utilized a hypothetical date of April 15, 1988 for Unit 2 commercial operation, but contemplated that an actual commercial operation date would be separately adopted. PSC confirmation of Unit 2 commercial operation as of April 5, 1988, as expected, would decrease the Company's write-off, whereas selection of a date later than the Company's previously assumed mid-May commercial operation date would require an additional write-off of approximately $6 million (net of tax) each month. In addition, resolution of the disputed items discussed below could result in additional adjustments to the Company's allowable investment in rate base.

Despite the Settlement and the PSC October 1986 order approving it, the co-tenants and PSC Staff have disagreed on its implementation and interpretation in several separate proceedings. In one proceeding stemming from a Niagara rate case the PSC disallowed costs for certain common facilities and certain other costs the co-tenants considered outside the scope of the Settlement. The Company's investment in these items at project completion is estimated to be $20 million. The PSC also decided that the tax benefits associated with the disallowance should be calculated on a discounted present value basis, utilizing a 34% tax rate rather than a 46% tax rate proposed by the co-tenants. The Company, in its 1987 write-offs (discussed below), did not recognize the effect of discounting in its determination of the Federal income tax benefits applicable

(Note 10 continued on page 30)

(Continued from page 29)

to the disallowance since the nominal tax benefits at the 34% rate will be ultimately recovered for the benefit of the shareholder. However, the PSC did discount these tax benefits in determining the regulatory disallowance in its June 1987 and July 1988 decisions. Thus, the regulatory disallowance was approximately $19 million greater than the Company has recognized for financial reporting purposes. This difference in regulatory treatment will, all other things being equal, result in a reported return on equity which will initially be less than the PSC authorized return on equity and which will be eliminated over the 10-year tax life of Unit 2. The PSC also determined that the entire amount of disallowed costs will be recognized as a write-off to common equity for rate-making purposes. On July 10, 1987, the co-tenants commenced an action in State Supreme Court, Albany County, seeking review of the PSC decision on the settlement implementation issues. In August 1987, the case was transferred to the Appellate Division, Third Department, and is pending.

≡ Other parties are also challenging the PSC's October 1986 order approving the Settlement. That appeal has also been transferred to the Appellate Division, Third Department, of State Supreme Court. Failure of the Settlement order to survive judicial challenge could result in the resumption of the PSC inquiry into the prudence of Unit 2 construction costs. It could also precipitate reinstatement of earlier PSC orders, superseded by the Settlement, which had adopted an incentive plan that limits rate recovery to 80% of those revenue requirements necessary to support Unit 2 capital costs exceeding $4.6 billion and then imposed a $5.4 billion cost cap on prudently incurred Unit 2 costs eligible for recovery through rates.

≡ In September 1987, the Company adopted SFAS-90 and recognized a loss from the disallowance arising from the Settlement. In adopting SFAS-90, the Company presented the cumulative effect of the accounting change prior to January 1, 1987 in the Statement of Income and did not restate previously issued annual financial statements. The disallowance was comprised of:

		(Dollars in Millions)
Cumulative Effect of Accounting Change		$258
Less—Related Federal Income Tax Benefits		(65)
Net Effect Prior to January 1, 1987		193
AFUDC Accrued in 1987 on Disallowed Project Costs		22
Additional Disallowed Plant Costs Recognized in 1987	$ 56	
Less—Related Federal Income Tax Benefits	(9)	
		47
Net Effect in 1987		69
Net Disallowance		$262

≡ The computation of the net disallowance as shown above was as follows:

		(Dollars in Millions)
Company Share of Total Plant Costs Based Upon Niagara's January 1988 Cost Estimate of $6.533 Billion including Prepaid Financing Charges and Adjusted for a Commercial Operation Date of mid-May 1988:		
Plant Costs	$591	
AFUDC	258	
Prepaid Financing Costs	102	
		$951
Common Facilities and Unshared Costs which the Company Considers Outside the Scope of the Settlement and Which Are Being Litigated		20
Total Investment		971
Settlement Allowance Comprised of:		
Plant Costs	480	
Prepaid Financing Costs	102	
		582
Amount Disallowed		389
Less—Payment from Niagara Mohawk		(41)
—Federal Income Tax Benefits		(74)
—AFUDC		(12)
Net Disallowance		$262

≡ Earnings information for 1988 as reported and for 1987 and 1986 modified to exclude the write-off and applicable AFUDC is as follows:

	December 31, 1988	1987	1986
Earnings Applicable to Common Stock (000's)	$68,766	$63,042	$67,161
Weighted average number of shares (000's)	30,513	29,728	28,927
Earnings per Common Share	$2.25	$2.12	$2.32

≡ In subsequent rate cases of some of the co-tenants, the Staff of the PSC has argued that certain post-in-service capital additions for Unit 2, estimated at $13 million for the Company, should be considered as falling under the scope of the Settlement cap and should not be afforded rate base treatment. The co-tenants disagree with the Staff's interpretation and vigorously oppose it. The settlement of the Niagara rate case, as well as that of the Company, contemplated a proceeding late in 1988 to examine on a single record these and similarly disputed amounts. This proceeding is now expected to begin following the conclusion of the current Unit 2 outage. The Company is unable to predict what position the PSC will ultimately adopt, and when and how much of these capital additions, if any, may have to be written off.

In an action stemming from a delay in Unit 2's testing and power ascension schedule occasioned by defects in the reactor's main steam isolation valves, the co-tenants in April 1987 commenced a lawsuit against three companies involved in the furnishing of that equipment. On August 1, 1988, the co-tenants commenced a second lawsuit, this one against both the firm furnishing architect-engineering and construction-management services and a company which fabricated and erected piping for Unit 2. This second suit seeks damages arising from the breach of certain obligations in the contractual arrangements with the defendants, which actions led to redesign, reconstruction and higher cost for the completed work. The parties are currently engaged in discovery procedures in both lawsuits. The Company cannot predict whether these suits will be successful or the amount of damages, if any, which may be recovered.

On January 26, 1989 the co-tenants entered into an agreement with General Electric Company (GE) relating to certain disputes which arose in connection with the Nuclear Steam Supply System (NSSS) portion of the construction of Unit 2, providing for settlement, mutual releases, and confidentiality of the specific elements of the agreement. The agreement provides that GE will supply certain goods and services to the co-tenants over a period of years without cost or at a reduced cost. Among other things, GE will supply engineering services which will improve Unit 2's technical specifications and which may ultimately result in the increased capacity of Unit 2; software designed to help avoid unplanned outages; other goods and services in support of Unit 2; and other goods and services relating to turbine upgrading and maintenance at co-tenants' generating facilities.

GE will receive indemnification from the co-tenants against any future judgments against GE brought by other Unit 2 contractors related to the NSSS portion of the construction of Unit 2, to the extent such judgments result from successful co-tenant claims against the contractors, and also indemnification for a portion of certain legal fees which GE may incur.

The present value of the goods and services will be recorded as an asset on the Company's balance sheet in 1989 with an offsetting deferred credit also being recorded, pending resolution of the rate treatment of the Settlement. While the Company does not believe the current treatment of the Settlement is material, the Company regards this as a favorable settlement. No part of the Settlement will be included in income pending PSC concurrence with the co-tenants' proposed accounting for such settlement and related expenses.

The directors of the Company in Fall 1986 received a demand letter, from a lawyer purporting to represent two shareholders of the Company, threatening to bring a shareholders' derivative action on behalf of the Company. The letter demanded that the directors take legal action against officers and directors responsible for what it alleged are losses sustained by the Company because of its investment in, and purported mismanagement of, the Unit 2 project. The Secretary of the Company responded to this letter and to a follow-up one by stating that the Board did not believe that, under then current circumstances, any further investigation into the demands was warranted and requesting a statement of any specific facts believed to require action. Neither the directors nor the Company officers have received further communications from this party on this matter in some two years, but the same firm represents certain shareholders of Niagara in derivative litigation commenced against that company's present and former officers and directors in May 1988. That suit seeks, in addition to the costs of the litigation itself, damages allegedly sustained by Niagara shareholders both from defendants' mismanagement of construction of Unit 2, and resulting disallowance imposed in settlement with the PSC, and from their concealment and fraud in failing to disclose such mismanagement. The Company is unable to predict whether the threats and demands received by it will lead to litigation similar to that in which Niagara is involved.

One of the co-tenant owners, LILCO, continues to experience governmental pressures, financial problems and other difficulties that could adversely affect its interest in Unit 2. State legislation enacted in 1986 created a public authority for the express purpose of taking over LILCO and, among other things, disposing of its interest in Unit 2. In mid-1988, LILCO and various parties opposing its efforts to license and operate the Shoreham Nuclear Plant reached a settlement which, had it gone into effect, would have ended the threat of LILCO takeover and attendant disposition of Unit 2. While certain conditions prerequisite to the Settlement's effectiveness were met, others were not and its status remains uncertain. LILCO is understood to be paying its share of ongoing Unit 2 expenses and receiving its entitlement to power. There is no immediate indication that will change, but LILCO's weakened financial condition and other difficulties impeding resolution of the public takeover threat leave uncertain its longer-term participation in the Unit 2 co-tenancy.

Note 11. Commitments and Other Matters

Capital Expenditures. The Company's 1989 construction expenditures program involves an estimated expenditure of $125 million, including $4 million of AFUDC. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nine Mile Point Nuclear Plant. See Note 10.

Nuclear Plant Decommissioning. Under accounting procedures periodically reviewed by the PSC, the Company has been collecting in its electric rates amounts for the eventual decommissioning of its Ginna plant and, most recently, for its share of the decommissioning of Nine Mile Point Unit 2. In June 1988, the NRC issued new regulations establishing criteria for various facets of decommissioning including acceptable alternative methods, planning, funding and environmental review. The Company will comply with the NRC final rule by June 1990, submitting a funding plan and establishing an external decommissioning trust fund. To the extent that the NRC funding requirement is greater than the corresponding decommissioning costs allowed in rates by the PSC, the Company may be required to make deposits of the greater amount and will seek recovery in rates. The Company is not presently in a position to estimate the cost impact of any such difference or anticipate what actions the PSC will pursue in this matter.

Insurance. The Company is a member of Nuclear Electric Insurance Limited, which provides insurance coverage for the cost of replacement power during certain prolonged accidental outages of nuclear generating units and coverage for property losses in excess of $500 million at nuclear generating units. If an insuring program's losses exceeded its other resources available to pay claims, the Company could be subject to maximum assessments in any one policy year of approximately $2.5 million and $8.0 million in the event of losses under the replacement power and property damage coverages, respectively.

On August 22, 1988 the President signed into law the Price-Anderson Amendments Act of 1988 (the "Amendments"), legislation which significantly increased liability limits under the Price-Anderson Act, extended its effectiveness until the year 2002, and modified it in other respects. Under the legislation, the public liability limit with respect to a nuclear accident at a licensed reactor increased to approximately $7.3 billion. The difference between that amount and the amount of liability insurance currently available to the Company from commercial sources would continue to be funded by retrospective assessments, increased in amount by the 1988 legislation to $63 million per licensed facility for each nuclear incident, payable at a rate not to exceed $10 million per year. Those assessments are subject to periodic inflation-indexing and to a 5% surcharge if funds prove insufficient to pay claims. The Company's interests in two nuclear units could thus expose it to a potential payment for each accident of $71.8 million (inflation-indexed) through retrospective assessments of $11.4 million per year in the event of a sufficiently serious nuclear accident at its own or another U.S. commercial nuclear reactor. The Amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations whether or not a nuclear incident actually occurs, that Presidential compensation plans may provide coverage over and above that afforded under the Price-Anderson Act, and that a Presidential commission will study certain compensation issues which arose during consideration of the Amendments, notably coverage for latent illnesses attributable to an accident.

Effective January 1, 1988, coverage for claims alleging radiation-induced injuries to some workers at nuclear reactor sites was removed from the nuclear liability insurance policies purchased by the Company. Coverage for workers first engaged in nuclear-related employment at a nuclear site prior to January 1, 1988 continues to be provided under the existing nuclear liability insurance policies. Those workers first employed at a nuclear facility after January 1, 1988 are covered under a new, industry-wide insurance program. This new program contains a retrospective premium assessment feature whereby participants in the program could be assessed to pay incurred losses that exceed the program's reserves. Under the plan as currently established, the Company could be assessed a maximum of $2.6 million over the life of the insurance coverage.

Gas Cost Recovery. Throughout the late 1970's and early 1980's, many interstate natural gas pipelines signed long-term gas sales contracts with producers under which the pipelines were obligated to take delivery of a specified percentage of maximum contract volumes of natural gas or, if such quantities were not taken, to pay for them ("take-or-pay"). As a result of falling oil prices and a general trend towards energy conservation, many pipelines subsequently experienced a significant reduction in sales, leading to substantial take-or-pay liability to their producers. The Federal Energy Regulatory Commission (FERC), in response to this industry-wide problem, is allowing an interstate pipeline to pass through to its customers, including downstream pipelines and local gas distribution companies, between 25% and 50% of the pipeline's take-or-pay costs.

After receiving comments, the PSC appears to have concluded, in an order issued in October 1988, that it could deny recovery of pipeline take-or-pay costs billed by an interstate pipeline supplier and paid by a distribution company. No PSC response had been received on the Company's petition for reconsideration of that point as of mid-January 1989. The PSC has scheduled hearings to determine whether distribution companies should be required to absorb some portion of such take-or-pay costs and how that portion recoverable from ratepayers should be allocated among them. Staff of the PSC and the Company have entered into an interim settlement which would permit the Company to recover from ratepayers 65% of the take-or-pay costs during the continuation of the PSC proceeding but other parties to the proceeding oppose this interim settlement and the PSC had not acted on it as of mid-January 1989. At December 31, 1988 the Company had deferred $1.1 million of billed take-or-pay charges.

The Company is unable to predict whether the PSC will require that it absorb some portion of the take-or-pay costs billed by its interstate pipeline supplier or, if the PSC does so require, whether that action will survive judicial review. Moreover, because several pipelines currently have pending before FERC proposals for the recovery of take-or-pay costs, the Company is unable to estimate at this time its overall exposure to such costs.

PSC Fuels Audit. The Company was notified by the PSC in December 1988 that its Utility Operational Audit Section would conduct an audit of the Company's fuel procurement practices. The audit began in January 1989 with a series of informational requests, an introductory meeting of the PSC Audit Section with responsible Company employees for orientation and explanation of procedures, and initial identification of key Company files. The PSC personnel have indicated an interest in reviewing the Company's procurement of coal, oil and nuclear fuel. Their work, which is expected to include visits to Company generating stations as well as to mines, laboratories and other facilities involved in the procurement function, may take as long as a year to complete. The Company expects to be given an opportunity to comment on any findings and recommendations stemming from the audit. Similar audits at other New York utilities have produced recommendations that the PSC require refunds of a portion of rates charged to customers for fuel costs. The Company believes its fuel procurement practices to be sound, but is not able to predict what the PSC Audit Section may recommend or what action the PSC may take.

Environmental Matters. Operations of the Company's facilities are subject to various Federal, state and local environmental standards.

In 1985, the New York State Department of Environmental Conservation (NYSDEC) identified property in the vicinity of the Lower Falls of the Genesee River in Rochester as an inactive hazardous waste disposal site. The NYSDEC conducted an investigation with which the Company as an owner of a portion of the property cooperated and, in March 1988, released a report entitled "Expanded Phase I Investigation—Genesee River Gorge (Lower Falls)". That report includes an assessment of the adequacy of available data, makes recommendations for additional phased investigations and identifies property owners. The Company is included in the list of property owners; however, a list of potentially responsible parties has not yet been completed. The site has been assigned Classification 2, "significant threat to the public health or environment—action required," in the NYSDEC's registry of inactive waste sites. Cleanup of certain areas of the site may eventually be ordered by NYSDEC. At another location along the River where the Company owns property, a boring taken for a sewer system project in Fall 1988 showed a layer containing a black viscous material. There was no indication that the material is migrating and it does not appear to be linked to the Lower Falls site. The find was reported to the NYSDEC, but the Company is not aware of any investigation being conducted by the agency.

If the NYSDEC requires remediation of these sites by virtue of ownership and/or past site disposal activity, the Company may be fully or partially responsible for the costs of investigation and any site remediation. The Company cannot at this time predict whether the NYSDEC will investigate the material from the boring, what outcome will be reached in the Lower Falls site investigation, and, with respect to either location, what future studies may be performed, what remediation measures may be directed and what share of any such activities the Company may be asked to assume.

Other Matters. The Company's contract with the federal Department of Energy (DOE) for nuclear fuel enrichment services assures provision of 70% of the Ginna Nuclear Plant's requirements throughout its service life or 30 years, whichever is less. No payment

(Note 11 continued on page 34)

(Continued from page 33)

obligation accrues unless such enrichment services are needed. The Company has secured the remaining 30% of its Ginna requirements under additional arrangements with DOE through 1989 and for the years 1991 through 1995; it is currently reviewing its options for the remainder of 1990 requirements. The annual cost of enrichment services utilized for the three most recent years and that estimated for the next seven years (priced at the most current rate) are as follows:

1986	$5,400,000
1987	4,700,000
1988	5,300,000
1989–1990	3,700,000
1991–1995	5,500,000

There have been no significant developments in nine- and ten-year old suits brought in various courts against the Company seeking an aggregate of $34.5 million in compensatory and $64 million in punitive damages for what are alleged to be personal injuries sustained through radiation exposure in 1974 at the Company's Ginna Nuclear Plant. The Company's initial assessment led it to believe that plaintiffs would not prevail on the merits. The cases have been generally inactive and no discovery has taken place in any of them. The Company's insurer disclaimed coverage for punitive damages.

Related litigation seeking substantial compensatory and punitive damages, brought by some of the plaintiffs against the Company over an interoffice memorandum, has been concluded successfully with no payment by the Company or its insurer.

Report of Independent Accountants

Price Waterhouse

1900 Lincoln First Tower
Rochester, New York 14604
January 26, 1989

To the Shareholders and Board of Directors of
Rochester Gas and Electric Corporation

In our opinion, the accompanying balance sheets and the related statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation at December 31, 1988 and 1987, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1988, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As described in Note 10, the Company adopted in 1987 Statement of Financial Accounting Standards No. 90 "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs." The adoption of this Statement resulted in the disallowed portion of the Company's investment in the Nine Mile Point Nuclear Plant Unit No. 2 (Unit) being recognized as a loss in the 1987 financial statements.

As a result of continuing uncertainties with respect to the Unit discussed in Note 10, the Company is unable to predict whether further regulatory actions by the New York State Public Service Commission with respect to its investment in the Unit will have, in the aggregate, a material effect on its financial position or results of operations. Accordingly, no provision for any additional loss that may result upon resolution of these uncertainties has been made in the accompanying financial statements.

Price Waterhouse

Common Stock and Dividends

Dividend Policy

The Company has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. The Company expects to continue this policy, although the level of future dividend payments is necessarily dependent on the Company's future earnings, its cash flow and additional factors discussed under the heading Earnings/Summary presented in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1989, the Company paid a cash dividend of $.375 per share on its Common Stock. Quarterly dividends have been paid at this rate since October 1987, when the dividend was reduced from a quarterly rate of $.55 per share. The October 1987 reduction resulted from the Company's analysis of its 1987 rate decision, wherein the PSC recognized the disallowance of certain Nine Mile Two plant costs for rate-making purposes. The Company's analysis indicated that the rate increase granted was not adequate to maintain the quarterly Common Stock dividend at the prior level of $.55 per share.

The Company's Certificate of Incorporation provides for the payment of dividends on Preferred Stock and Common Stock out of the surplus net profits (retained earnings) of the Company. The Company presently intends to establish a retained earnings base at least equal to its annual dividend requirement for both Preferred Stock and Common Stock before considering an increase in the Common Stock dividend rate above the current quarterly rate.

Automatic Dividend Reinvestment and Stock Purchase Plan

Common Stock shareholders may have the dividends on all, or any designated number, of their shares automatically reinvested in additional shares of Common Stock by participating in the Company's Automatic Dividend Reinvestment and Stock Purchase Plan. Participants may also make optional cash payments of up to $5,000 each month to acquire additional shares, whether or not they reinvest their dividends. Optional cash payments need not be made on a monthly or other recurring basis. Participants may change their method of participation, withdraw from the Plan or re-enroll as often as they wish. More information on the automatic reinvestment of dividends may be obtained by writing to the Agent, Chase Lincoln First Bank, N.A., Corporate Agency Department, Post Office Box 1507, Rochester, New York 14603 or by calling the Agent at (716) 258-5854.

Tax Status of Cash Dividends

Cash dividends paid in 1988, 1987 and 1986 were 100 percent taxable for Federal income tax purposes.

Earnings and Dividends

	1988	1987	1986
Earnings per weighted average share			
Total	**$2.25**	$(5.95)	$3.33
Before cumulative effect of accounting change	**$2.25**	$ .54	$3.33
Number of shares (000's)			
Weighted average	**30,513**	29,728	28,927
Actual number at December 31	**30,786**	30,121	29,247
Number of shareholders at December 31	**41,834**	44,127	45,959
Cash dividends paid			
1st quarter	**$.375**	$ .55	$.55
2nd quarter	**.375**	.55	.55
3rd quarter	**.375**	.55	.55
4th quarter	**.375**	.375	.55

Common Stock Trading

Shares of the Company's Common Stock are traded on the New York Stock Exchange under the symbol "RGS".

	1988	1987	1986
Common Stock—Price Range			
High			
1st quarter	**17½**	25⅞	28
2nd quarter	**18¼**	19⅞	28¼
3rd quarter	**18¼**	18⅜	29⅞
4th quarter	**17⅞**	17¼	25⅜
Low			
1st quarter	**14¾**	19⅞	22⅜
2nd quarter	**15¾**	15⅝	24⅛
3rd quarter	**16⅜**	16¾	24¾
4th quarter	**16¾**	14¼	21¼

Shareholder Profile—December 31, 1988

Common Stock Shareholders	
Women	13,284
Men	12,031
Joint Accounts	10,585
Fiduciaries, Nominees, Others	5,934
Location	
United States, Except New York State	22,185
New York State, Except Franchise Area	7,163
Franchise Area	12,352
Foreign Countries	134
Shareholders Owning	
1–200 shares	22,479
201–500	11,322
501–1,000	4,839
Over 1,000	3,194

Selected Financial Data

Summary of Operations

(Thousands of Dollars) Year Ended December 31	1988	1987	1986	1985	1984	1983
Operating Revenues						
Electric	$ 513,617	$ 489,215	$466,496	$429,450	$416,856	$407,948
Gas	230,395	216,058	261,688	269,562	291,628	276,357
	744,012	705,273	728,184	699,012	708,484	684,305
Electric sales to other utilities	29,966	26,215	20,465	44,103	60,103	55,644
Total Operating Revenues	773,978	731,488	748,649	743,115	768,587	739,949
Operating Expenses						
Fuel Expenses						
Electric fuels	64,767	61,292	52,186	64,776	82,106	88,745
Purchased electricity	30,299	26,467	30,144	27,804	35,497	33,820
Gas purchased for resale	128,774	121,736	160,904	174,644	187,453	189,526
Total Fuel Expenses	223,840	209,495	243,234	267,224	305,056	312,091
Operating Revenues Less Fuel Expenses	550,138	521,993	505,415	475,891	463,531	427,858
Other Operating Expenses						
Operations excluding fuel expenses	159,689	159,170	148,340	129,273	131,670	132,032
Maintenance	52,575	46,124	44,767	42,518	41,013	39,418
Depreciation and Amortization	69,703	55,530	52,072	46,716	42,199	39,279
Taxes—local, state and other	88,635	82,869	84,590	81,983	83,013	80,118
Federal income tax—current	20,363	32,781	22,521	12,974	15,724	5,390
—deferred	20,299	23,144	37,304	44,978	41,885	32,794
Total Other Operating Expenses	411,264	399,618	389,594	358,442	355,504	329,031
Operating Income	138,874	122,375	115,821	117,449	108,027	98,827
Other Income and Deductions						
Allowance for other funds used during construction	2,047	5,030	32,828	38,393	33,782	25,697
Federal income tax	1,683	17,520	13,880	13,344	13,356	9,724
Disallowed project costs	—	(55,860)	—	—	—	—
Other, net	6,901	8,831	6,725	3,899	261	1,579
Total Other Income and Deductions	10,631	(24,479)	53,433	55,636	47,399	37,000
Income before Interest Charges	149,505	97,896	169,254	173,085	155,426	135,827
Interest Charges						
Long term debt	72,270	73,489	74,571	70,373	63,103	56,761
Short term debt	—	129	68	—	19	936
Other, net	2,898	2,685	2,074	2,227	2,464	2,048
Allowance for borrowed funds used during construction	(1,777)	(2,696)	(11,978)	(14,339)	(12,741)	(10,168)
Total Interest Charges	73,391	73,607	64,735	58,261	52,845	49,577
Income from Continuing Operations, Before Cumulative Effect of Accounting Change	76,114	24,289	104,519	114,824	102,581	86,250
Discontinued Steam Operations	—	—	—	(6,356)	1,037	(2)
Cumulative Effect for Years Prior to 1987 of Accounting Change for Disallowed Costs	—	(193,000)	—	—	—	—
Net Income (Loss)	76,114	(168,711)	104,519	108,468	103,618	86,248
Dividends on Preferred and Preference Stock, at required rates	7,348	8,147	8,058	9,467	12,213	10,515
Earnings (Loss) Applicable to Common Stock	$ 68,766	$(176,858)	$ 96,461	$ 99,001	$ 91,405	$ 75,733
Weighted Average Number of Shares Outstanding in Each Period, (000's)	30,513	29,728	28,927	27,641	25,101	23,389
Earnings (Loss) per Common Share—Total	$2.25	$(5.95)	$3.33	$3.58	$3.64	$3.23
Earnings (Loss) per Common Share—Continuing Operations	$2.25	$ .54	$3.33	$3.81	$3.60	$3.23
Cash Dividends Paid per Common Share	$1.50	$2.025	$2.20	$2.20	$2.04	$1.84

Condensed Balance Sheet

(Thousands of Dollars) At December 31	1988	1987	1986	1985	1984	1983
ASSETS						
Utility Plant	$2,122,922	$1,559,848	$1,531,019	$1,446,916	$1,394,375	$1,310,459
Less—Accumulated depreciation and amortization	653,876	586,840	571,022	532,947	489,938	449,807
	1,469,046	973,008	959,997	913,969	904,437	860,652
Construction work in progress	41,044	501,738	768,905	710,194	554,331	424,875
Net utility plant	1,510,090	1,474,746	1,728,902	1,624,163	1,458,768	1,285,527
Current Assets	211,313	184,309	141,222	144,217	151,042	135,403
Deferred Debits	102,015	131,526	114,340	82,092	64,269	75,927
Total Assets	$1,823,418	$1,790,581	$1,984,464	$1,850,472	$1,674,079	$1,496,857
CAPITALIZATION AND LIABILITIES						
Capitalization						
Long term debt	$ 792,976	$ 845,326	$ 773,082	$ 765,511	$ 678,018	$ 611,282
Preferred stock redeemable at option of Company	67,000	67,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	30,000	50,797	43,485	45,922	47,562	49,187
Preference stock subject to repurchase						28,000
Common shareholders' equity						
Common stock	504,907	494,018	479,704	461,078	405,200	385,921
Retained earnings	39,710	17,617	249,505	216,795	179,676	153,142
Total common shareholders' equity	544,617	511,635	729,209	677,873	584,876	539,063
Total Capitalization	1,434,593	1,474,758	1,612,776	1,556,306	1,377,456	1,294,532
Long Term Liability—Department of Energy	51,016	47,773	44,950	42,214	39,084	35,363
Current Liabilities	126,233	90,504	118,348	98,270	131,108	81,602
Deferred Credits and Other Liabilities	211,576	177,546	208,390	153,682	126,431	85,360
Total Capitalization and Liabilities	$1,823,418	$1,790,581	$1,984,464	$1,850,472	$1,674,079	$1,496,857

Financial Data

At December 31	1988	1987	1986	1985	1984	1983
Capitalization Ratios* (percent)						
Long term debt	56.8	58.7	49.3	50.5	50.6	48.6
Preferred and preference stock	6.5	7.7	6.7	7.1	8.1	10.9
Common shareholders' equity	36.7	33.6	44.0	42.4	41.3	40.5
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$17.69	$16.98	$24.93	$23.79	$22.78	$22.09
Rate of Return on Average Common Equity (percent)	12.68	12.45**	13.38	14.93	16.01	14.97
Embedded Cost of Senior Capital (percent)						
Long term debt	8.71	8.90	9.36	9.88	9.91	10.07
Preferred stock	6.72	7.09	7.20	7.27	7.37	7.37
Effective Federal Income Tax Rate (percent)	33.9	61.3	30.5	28.0	30.1	24.8
Depreciation Rate (percent)—Electric	3.56	3.50	3.50	3.40	3.30	3.23
—Gas	2.96	2.98	2.99	2.98	3.12	2.96
Interest Coverages***						
Before federal income taxes (incld. AFUDC)	2.53	2.55	2.96	3.08	3.26	2.91
(excld. AFUDC)	2.48	2.45	2.38	2.35	2.55	2.31
After federal income taxes (incld. AFUDC)	2.01	1.93	2.36	2.49	2.58	2.44
(excld. AFUDC)	1.96	1.83	1.78	1.77	1.87	1.84

**Includes Company's long term liability to the Department of Energy.*

***Excludes disallowed Nine Mile Two plant costs written off in 1987.*

****AFUDC included in interest coverages prior to 1987 has not been restated to reflect the disallowance of certain Nine Mile Two plant costs recognized by the Company in 1987.*

Electric Department Statistics

Year Ended December 31	1988	1987	1986	1985	1984	1983
Electric Revenue (000's)						
Residential	$188,451	$178,933	$166,664	$155,193	$147,500	$143,455
Commercial	149,663	146,138	137,077	122,292	118,628	118,610
Industrial	120,490	118,479	116,321	110,135	109,052	103,598
Other	55,013	45,665	46,434	41,830	41,676	42,285
Electric revenue from our customers	513,617	489,215	466,496	429,450	416,856	407,948
Other electric utilities	29,966	26,215	20,465	44,103	60,103	55,644
Total electric revenue	543,583	515,430	486,961	473,553	476,959	463,592
Electric Expense (000's)						
Fuel used in electric generation	64,767	61,292	52,186	64,776	82,106	88,745
Purchased electricity	30,299	26,467	30,144	27,804	35,497	33,820
Other operation	124,871	126,320	113,497	96,194	97,612	100,412
Maintenance	44,060	37,641	36,573	35,013	33,535	32,444
Depreciation and Amortization	60,444	46,776	43,753	39,015	34,822	32,648
Taxes—local, state and other	66,426	61,504	61,314	58,867	59,215	57,931
Electric revenue deductions	390,867	360,000	337,467	321,669	342,787	346,000
Operating Income before Federal Income Tax	152,716	155,430	149,494	151,884	134,172	117,592
Federal income tax	34,093	48,788	52,051	52,068	47,410	34,339
Operating Income from Electric Operations (000's)	$118,623	$106,642	$ 97,443	$ 99,816	$ 86,762	$ 83,253
Electric Operating Ratio %	48.6	48.8	47.7	47.3	52.2	55.1
Electric Sales—KWH (000's)						
Residential	2,051,808	1,970,345	1,890,293	1,846,993	1,834,564	1,788,785
Commercial	1,792,162	1,732,939	1,657,606	1,591,670	1,539,662	1,491,736
Industrial	1,869,417	1,782,223	1,775,722	1,814,460	1,783,415	1,609,787
Other	483,730	463,256	452,756	452,142	452,189	462,089
Electric sales to our customers	6,197,117	5,948,763	5,776,377	5,705,265	5,609,830	5,352,397
Other electric utilities	1,149,900	1,047,654	925,318	1,404,504	1,554,392	1,370,239
Total electric sales	7,347,017	6,996,417	6,701,695	7,109,769	7,164,222	6,722,636
Electric Customers at December 31						
Residential	290,037	285,988	281,630	277,758	273,050	268,764
Commercial	27,888	27,383	26,865	26,184	25,432	24,998
Industrial	1,392	1,381	1,368	1,362	1,459	1,425
Other	2,326	2,281	2,266	2,254	2,249	2,151
Total electric customers	321,643	317,033	312,129	307,558	302,190	297,338
Electricity Generated and Purchased—KWH (000's)						
Fossil	2,214,588	1,877,922	1,491,167	2,211,246	2,285,761	2,431,144
Nuclear	3,884,884	3,793,021	3,603,116	3,613,104	3,143,923	3,027,160
Hydro	169,002	223,958	235,175	153,636	218,228	200,325
Pumped storage	292,305	246,925	237,663	240,375	205,760	226,612
Less energy for pumping	(430,401)	(387,546)	(353,735)	(373,537)	(311,710)	(342,853)
Other	2,195	4,554	1,850	4,354	3,846	3,111
Total generated—Net	6,132,573	5,758,834	5,215,236	5,849,178	5,545,808	5,545,499
Purchased	1,705,755	1,703,411	1,945,586	1,713,481	2,037,936	1,609,553
Total electric energy	7,838,328	7,462,245	7,160,822	7,562,659	7,583,744	7,155,052
Electric Generation Costs (000's)						
Fossil	$ 65,274	$ 59,695	$ 51,056	$ 71,898	$ 72,706	$ 80,909
Nuclear	74,661	58,965	56,136	49,772	50,020	45,904
Hydro	2,772	1,695	2,134	1,616	1,504	1,180
Other	401	465	274	776	362	431
Electric Department Fuel						
Fossil —Total BTU (million)	23,425,796	20,083,347	15,896,376	23,140,883	23,627,034	25,670,771
—Cents per million BTU	201.40	209.55	216.69	237.09	232.64	252.67
Nuclear—Total BTU (million)	41,662,677	40,538,534	38,660,500	39,034,016	34,225,538	33,020,145
—Cents per million BTU	49.07	52.30	48.49	46.85	50.67	57.38
System Net Capability—KW at December 31						
Fossil	541,000	541,000	510,000	587,000	587,000	605,000
Nuclear	621,000	470,000	470,000	470,000	470,000	470,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	29,000	29,000	29,000	29,000	29,000	29,000
Purchased	360,000	363,000	356,000	352,000	355,000	353,000
Total system net capability	1,598,000	1,450,000	1,412,000	1,485,000	1,488,000	1,504,000
Net Peak Load—KW	1,275,000	1,205,000	1,100,000	1,076,000	1,075,000	1,037,000
Annual Load Factor—Net %	60.0	60.8	64.7	65.4	63.9	63.9

Gas Department Statistics

Year Ended December 31	1988	1987	1986	1985	1984	1983
Gas Revenue (000's)						
Residential	$ 6,439	$ 6,436	$ 7,694	$ 8,403	$ 8,924	$ 8,910
Residential spaceheating	150,383	138,552	156,120	153,279	162,727	153,167
Commercial	44,781	43,311	52,653	53,568	56,518	53,636
Industrial	9,859	10,842	28,800	38,837	46,518	44,552
Municipal and other	18,933	16,917	16,421	15,475	16,941	16,092
Total gas revenue	230,395	216,058	261,688	269,562	291,628	276,357
Gas Expense (000's)						
Gas purchased for resale	128,774	121,736	160,904	174,644	187,453	189,526
Other operation	34,818	32,850	34,843	33,079	34,058	31,620
Maintenance	8,515	8,483	8,194	7,505	7,478	6,974
Depreciation	9,259	8,754	8,319	7,701	7,377	6,631
Taxes—local, state and other	22,209	21,365	23,276	23,116	23,798	22,187
Gas revenue deductions	203,575	193,188	235,536	246,045	260,164	256,938
Operating Income before Federal Income Tax	26,820	22,870	26,152	23,517	31,464	19,419
Federal income tax	6,569	7,137	7,774	5,884	10,199	3,845
Operating Income from Gas Operations (000's)	$ 20,251	$ 15,733	$ 18,378	$ 17,633	$ 21,265	$ 15,574
Gas Operating Ratio %	74.7	75.5	77.9	79.8	78.5	82.5
Gas Sales—Therms (000's)						
Residential	10,374	10,255	11,382	12,296	12,746	12,323
Residential spaceheating	267,697	244,655	253,101	244,593	252,518	232,380
Commercial	86,413	83,167	92,864	93,283	95,427	88,501
Industrial	20,174	22,033	56,621	76,263	90,266	82,895
Municipal	15,514	17,985	23,405	24,848	26,937	24,661
Total gas sales to our customers	400,172	378,095	437,373	451,283	477,894	440,760
Transportation of customer-owned gas	83,594	67,496	24,589	618	—	—
Total gas sold and transported	483,766	445,591	461,962	451,901	477,894	440,760
Gas Customers at December 31						
Residential	24,139	24,834	25,865	27,202	28,438	29,246
Residential spaceheating	210,710	206,458	201,227	196,035	191,192	187,071
Commercial	17,213	16,771	16,330	15,816	15,323	15,020
Industrial	1,042	1,035	1,015	1,029	1,019	977
Municipal	1,039	1,026	1,009	990	977	970
Total gas customers	254,143	250,124	245,446	241,072	236,949	233,284
Gas—Therms (000's)						
Purchased for resale	408,044	381,632	439,381	469,386	475,976	462,357
Other	1,967	2,317	5,996	14,943	18,039	16,479
Total gas available	410,011	383,949	445,377	484,329	494,015	478,836
Cost of gas per therm	31.76¢	32.51¢	35.82¢	37.53¢	38.52¢	40.51¢
Total Daily Capacity—Therms at December 31*	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000	4,150,000
Maximum daily throughput—Therms	3,744,500	3,443,240	3,499,640	3,746,980	3,711,490	3,456,050
Degree Days (Customer Billing)						
For the period	6,871	6,439	6,742	6,412	6,784	6,305
Percent colder (warmer) than normal	1.2	(4.6)	1.3	(5.0)	1.1	(6.3)

**Method for determining daily capacity, based on current network analysis, reflects the maximum demand which the transmission system can accept without a deficiency.*

Interim Financial Data

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results of operations for such periods. The variations in operations reported on a quarterly basis are a result of the seasonal nature of the Company's business and the availability of the Company's Ginna Nuclear Plant. The cumulative effect of the accounting change related to the Nine Mile Two disallowed project costs and related write-offs during the year 1987 are discussed in Note 10 of the Notes to the Financial Statements.

	(Thousands)				
Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Earnings (Loss) on Common Stock	Earnings (Loss) Per Common Share (in dollars)
December 31, 1988	**$197,879**	**$26,454**	**$ 10,577**	**$ 9,071**	**$ .29**
September 30, 1988	**172,848**	**37,879**	**21,979**	**20,079**	**.65**
June 30, 1988	**166,615**	**28,396**	**12,517**	**10,546**	**.34**
March 31, 1988	**236,635**	**46,145**	**31,042**	**29,071**	**.96**
December 31, 1987	$177,764	$25,256	$ (9,771)	$ (11,742)	$ (.39)
September 30, 1987	165,281	32,272	20,268	18,297	.61
June 30, 1987	157,193	24,271	12,686	10,715	.36*
March 31, 1987	231,250	40,576	(191,894)	(194,128)	(6.60)*
December 31, 1986	$180,634	$23,433	$ 18,910	$ 16,926	$ .57
September 30, 1986	150,835	26,664	22,620	20,636	.71
June 30, 1986	162,991	24,539	23,130	21,085	.73
March 31, 1986	254,189	41,185	39,859	37,814	1.32

**Restated from published quarterly data. The cumulative effect of the accounting change ($193 million, net of Federal income tax benefits) has been reflected in the first quarter restatement. The first and second quarters reflect the discontinuance of AFUDC on the disallowed project costs. (See Note 10 of the Notes to the Financial Statements.)*

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(As of January 1, 1989)

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