NIAGARA MOHAWK POWER CORPORATION

1989 ANNUAL REPORT

This is our seven-point plan for long-term prosperity – a prosperity in which all important constituencies share, our customers, employees and stockholders.

William J. Donlon
Chairman and CEO
May 2nd, 1989

Highlights of 1989

	1989	1988	% Change
Total operating revenues	$ 2,906,043,000	$ 2,800,453,000	3.8
Income available for common stockholders	$ 105,601,000	$ 159,657,000	(33.9)
Earnings per common share	$ .78	$1.21	(35.5)
Dividends per common share	$ .60	$1.20	(50.0)
Common shares outstanding *(average)*	136,052,000	131,853,000	3.2
Utility plant *(gross)*	$ 8,324,112,000	$ 7,967,625,000	4.5
Construction work in progress	$ 387,520,000	$ 315,644,000	22.8
Gross additions to utility plant	$ 411,887,000	$ 366,142,000	12.5
Public kilowatt-hour sales	34,201,000,000	33,263,000,000	2.8
Total kilowatt-hour sales	35,396,000,000	34,995,000,000	1.1
Electric customers at end of year	1,504,000	1,482,000	1.5
Electric peak load *(kilowatts)*	6,376,000	6,220,000	2.5
Natural gas sales *(dekatherms)*	80,677,000	81,448,000	(.9)
Natural gas transported *(dekatherms)*	33,769,000	27,244,000	24.0
Gas customers at end of year	466,000	458,000	1.7
Maximum day gas deliveries *(dekatherms)*	802,909	818,128	(1.9)

Contents

Serving our Customers in Upstate New York

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

Our electric system extends from Lake Erie to New England's borders, from Canada to Pennsylvania, and meets the needs of over 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 services approximately 466,000 residential and business customers with access to our 6,500-mile system 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. The financial section and cover of this annual report are printed on recycled paper stock.

We have closed out what was certainly the most difficult decade of Niagara Mohawk's history. And if one year was representative of the decade as a whole, it was 1989. It was at once a year of change, disappointment and progress.

Looking only to financial matters, the past year was certainly disappointing as we failed to meet many of the expectations we had for company performance.

Earnings for 1989 were $105.6 million or $.78 per share, compared with $159.7 million or $1.21 per share in 1988. A downward trend in earnings and earnings per share has continued since 1987, when we took an after-tax write-off of $833 million in disallowed Nine Mile Two costs.

Two factors were prime contributors during 1989 to the continuing decline in earnings:

- Higher-than-expected operating expenses, particularly those associated with the Nine Mile One outage;
- An agreement with the New York State Public Service Commission and other parties, under which we absorbed nearly $41 million in replacement power costs from the Nine Mile One outage during the first six months of the year.

Return on common equity declined to 5.6 percent for 1989, compared with 8.7 percent in 1988. There is potential for improvement in 1990 if we are successful in meeting the defined milestones in a self-assessment program we are undertaking, and if we are able to resolve our nuclear problems and restart Nine Mile One in accordance with our current schedule.

1989 in Perspective

Obviously, we did not accomplish all we set out to do in 1989. Our inability to bring Nine Mile One back into service after a two-year outage was the primary objective not attained during the year.

As a result of the prolonged outage, we were hampered in our efforts to control operating costs.

(Fuel loading at Nine Mile One was completed in January 1990, but we do not anticipate being ready to restart the plant before the second quarter of this year.)

Recognizing the difficulties we would face in 1989, we began in February to establish a dialogue with regulators, lawmakers and opinion leaders about the need for a better balance of interests between customers and shareholders.

As the primary provider of energy to more than 3.5 million New Yorkers, our slide into financial difficulty could not be allowed to continue without a detrimental effect on our ability to provide service to our customers.

At the same time, it was unrealistic to assume that our shareholders should shoulder the entire burden of our financial difficulties. Uncertainty within the investment community would serve only to exacerbate our already weakened financial condition.

Early in the year, we agreed to suspend collection of $225,000 per day in replacement power costs associated with the Nine Mile One outage to allow us to focus all our efforts on the restart of the unit.

Niagara Mohawk

We petitioned the Public Service Commission in May to allow us to retain cost savings realized through a change in the way we fund the portion of our pension program associated with those employees already retired. Through the purchase of a single premium annuity, we ultimately will realize savings of about $83 million.

In early August, we applied to the PSC for an increase in revenues of nearly $370 million, the largest request in the company's history. In December, that request was reduced to $344.5 million through the normal updating process. Base electric rates had not increased since March 1987, while gas rates had not increased since March 1985.

Under our previous electric and gas rate agreements, new rates could not take effect before mid-1990. Our filing was timed so that new rates could take effect with the expiration of the existing rate agreements.

A New Regulatory Agreement

Our communications efforts with our regulators culminated in the 1989 Regulatory Agreement that should afford us the breathing room we had been seeking to move ahead in areas we had identified for change and improvement. The agreement was signed late in August and approved by the PSC in October. It contains three basic elements:

- It provides needed financial relief by permitting us to collect replacement power costs associated with the Nine Mile One outage, as well as regulatory cost deferrals and a recovery mechanism intended to preserve interest coverage ratios at investment grade levels.
- It establishes a framework that will allow the company to resolve issues relating to rate relief, setting the stage for all parties to the agreement to discuss a multi-year plan that would be intended to ensure reasonable rates and financial strength.
- It provides that we will conduct a self-assessment of our organizational efficiency and effectiveness, with the goal of achieving financial and operating improvements.

In August, the Board of Directors voted to omit dividends on shares of common stock. At the same time, the Board reduced its fees, salaries of the Chairman and President were reduced, other officer salaries were frozen at current levels and we placed a cap on all new positions outside the Nuclear Division as further efforts to reduce costs.

As part of the agreement, we will not resume payment of common dividends at least until Nine Mile One returns to full service. We are committed to paying dividends to our shareholders at the earliest possible date, but such action is also dependent on our level of retained and future earnings, cash flow, financial requirements and other uncertainties.

A Focus on 1990

Three areas will receive particular attention in 1990: the self-assessment process; our ongoing regulatory dialogue; and continued efforts toward improving performance in our nuclear operations.

The self-assessment process will be a long-term effort, as we examine virtually every aspect of our operations. We have retained McKinsey and Company, a highly respected consulting firm, to assist us with this process. It has the full support of our Board of Directors and senior management team. As leaders of the company, we have taken personal and active roles in its implementation.

We are to submit a final report with recommendations to the PSC by November 15, 1990. One of our self-assessment goals, however, is to acquire and refine the skills necessary to continually examine and evaluate our organizational and operational effectiveness so that our efforts to achieve maximum efficiency extend beyond the formal conclusion of our assessment.

Self-assessment is just one piece of our efforts to improve relationships with our regulators. The agreement provides that all parties will discuss the settlement of issues related to our financial condition and regulatory situation, including the Nine Mile One prudence investigation.

While we can offer no assurances as to what the final outcome of these discussions will be, we are encouraged that negotiations are being carried out in an atmosphere of cooperation and constructive dialogue.

Another piece of our ongoing regulatory dialogue, and part of the agreement, is our study of the advantages and disadvantages of the separation, reorganization or other restructuring with respect to our natural gas business. This report is to be presented to the PSC no later than June 1, 1990.

And finally, we are seeking further improvements in our nuclear operations. Our goal in this area is not only to meet and exceed regulatory requirements, but to be recognized as a leader in the nuclear industry. We have made progress, but we have a long way to go.

Our nuclear facilities represent about 14 percent of our total generating mix. Yet so much of what Niagara Mohawk has accomplished has been overshadowed—financially and politically—by our difficulties in this arena.

At our last annual meeting, we outlined for shareholders a plan to achieve financial prosperity. We knew at the time that there were no short-term solutions to our difficulties, and that achievement of long-term financial strength would require long-range thinking.

We have made progress. And the challenge continues. On the pages that follow is a report on that plan and the progress we made in 1989.

John M. Endries
President

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

February 21, 1990

Financial strength: In 1989, we sought a balance of interests between shareholders and customers. We attempted to forge a more effective working relationship with our regulators, to achieve a degree of financial breathing room for the year, and to gain adequate revenue flow thereafter.

We made progress, but much remains to be done. The decisions we made in 1989 will enable us in 1990 to build a new framework for financial strength. A measure of success, we believe, will be our ability to resume payment of dividends on common stock at the earliest prudent date.

The regulatory agreement we reached in August with the state's Public Service Commission, Attorney General, Consumer Protection Board and Multiple Intervenors representing our largest industrial customers established a foundation upon which we feel we can effectively administer our ongoing programs for financial recovery.

These include our Nuclear Improvement Program, the Restart Action Plan for Nine Mile One, a continuing focus on strengthening customer service and cost containment in the areas of operating expenses, construction programs and power production.

The agreement established a targeted minimum level of financial strength, measured on the basis of interest coverage ratios, in our effort to maintain the investment grade credit ratings on our bonds so vital to our financing efforts. It also allowed us to resume full collection of replacement power costs associated with the Nine Mile One outage, effective July 1, 1989.

The agreement provides a framework for regulatory cooperation in the resolution of a number of outstanding financial matters, including a multi-year rate plan, the Nine Mile One outage prudence investigation and unresolved Nine Mile Two issues.

The agreement opened the door for Niagara Mohawk to initiate—in concert with regulators—a detailed examination of our strengths and weaknesses. We are now conducting an intensive self-assessment of our operating and management practices.

We intend to present to the Commission this November a detailed report covering our self-assessment that will include recommendations for enhancing our organizational and operational capabilities. Our goal is to strive for maximum corporate efficiency and effectiveness.

Such an agreement requires sacrifice; most notably, the omission of common stock dividends at least until Nine Mile One is returned to full service and the continuation of the freeze on base electric and gas rates until January, 1991.

Also, higher-than-anticipated operating expenses, including those associated with the Nine Mile One outage, had a draining effect on earnings despite higher sales in all ultimate customer categories.

Our financial condition was such that the decision by the Board of Directors to omit common dividends was a necessary step toward regaining financial strength. The agreement and its provisions for addressing unresolved issues will allow us to better examine our goals, and the cost of those goals. We intend to work earnestly with regulators to resolve the multitude of open issues, each

having the potential for adverse financial consequences, and to establish new rates that offer a reasonable price for customers and a fair return for shareholders.

We already are working with the other parties to our regulatory agreement to negotiate a multi-year rate pact, which will include incentive return mechanisms tied to the recommendations from self-assessment, with the aim of improving earnings for shareholders, securing rate stability for our customers and obtaining financial stability for the company.

These discussions should reach conclusion very late in 1990. If permanent rates are not established by January 1, 1991, temporary rates will take effect. Under the agreement, permanent rates must be established by the Public Service Commission not later than March 1, 1991.

At the time we began these negotiations early in 1989, we fully understood that complete financial recovery for Niagara Mohawk could not be attained in a single year.

The complexity of the 1989 agreement is a reflection of the many changes in the structure of our industry, and in the way it is regulated and monitored. However, we believe we have laid a foundation we can successfully build on in the 1990s.

FINANCIAL STRENGTH:

"I have always thought of the utility business as a vessel for combining the interests of shareholders, customers and the state for mutual benefit. Without this balance, individuals and institutions will be reluctant to invest in utilities. This clearly is not in anyone's best interest."

William J. Donlon
Chairman and CEO
May 2, 1989

System reliability is the heart and soul of the utility business. For Niagara Mohawk, it means having access to adequate sources of energy supply and an efficient transmission and distribution network to deliver it.

Our efforts over the years in obtaining, generating and supplying energy have provided us with an impressive array of resources to meet the needs of our customers. In 1989, we strengthened our capabilities on several fronts.

We broke new ground last fall with our invitation to all interested parties to compete for the supply of 350 megawatts of new electrical capacity. The request for proposals is the first test of the company's all-source bidding program, adopted by the company and approved by the Public Service Commission in 1989.

Dozens of developers have expressed interest in our request for proposals. All bids, including our own proposal to extend the life of two generators at our Huntley Steam Station, will be screened and ranked by an independent party prior to the company's final evaluation process.

Conservation and load-management programs could account for as much as 50 megawatts of the needed capacity. We expect to award

the contracts in August, with the new capacity expected to be available by 1994.

Our bidding program is embodied in the Niagara Mohawk Integrated Electric Resource Plan, adopted in 1989. The plan delineates the process by which we will identify future capacity needs and how the company will acquire those resources.

Among existing resources, Niagara Mohawk's fossil fuel and hydroelectric generating stations contributed significantly to our ability to meet customer demand in 1989. In fact, our fossil stations broke records for electrical production set only a year earlier, generating 17,900 millions of kilowatt-hours, thus exceeding 1988's output by 9.3 percent.

Hydroelectric production also was improved as the 74 hydroelectric stations we operate and maintain generated more than 3,675 millions of kilowatt-hours, 16 percent more than 1988.

We intend to continue our legacy of making efficient and environmentally-sound use of waterways in our service territory. To that end, we intend to seek new licenses at our 30 hydro stations where existing licenses expire in 1993, and anticipate hydro construction and rehabilitation expenditures of some $30 million in 1990 alone.

Competition for these licenses is expected to be stiff at several sites, but we are confident that our record of low-cost generation and environmental sensitivity should prevail. Our support of the burgeoning fisheries and recreation industry along these waterways has grown dramatically in recent years, illustrating our stewardship of this irreplaceable natural resource.

Niagara Mohawk also has made significant strides in securing adequate and cost-effective supplies of natural gas. The New York State Energy Master Plan was unveiled in Albany in 1989. The plan strongly recommends the continued and expanded use of natural gas as an economical and environmentally-sound energy source.

SYSTEM RELIABILITY:

"Since its incorporation nearly 40 years ago, Niagara Mohawk has worked hard to keep a broad portfolio of energy resources at its disposal. As a result, we manage an enviable mix of coal, oil, gas, nuclear and hydroelectric generating sources. Recently, we began full-scale implementation of another important resource—a range of conservation and load management programs that will improve our system's efficiency."

Anthony J. Baratta
Senior Vice President
Corporate Services
December 15, 1989

We are moving to support this effort through increased purchases of natural gas on the spot market, securing adequate supplies while lowering costs for our customers. Since we initiated spot-market purchasing in 1984, we gradually have increased the volume of gas bought to about 35 percent of our total annual purchases, saving our customers more than $26 million in 1989.

Late in 1989, the Canadian National Energy Board rejected several natural gas export applications, including one that would have allowed Niagara Mohawk for the first time to tap into the vast reserves in western Canada. We are appealing that decision and, if successful, will resume our plans to construct the Trans York Pipeline. The project would cross the St. Lawrence River, delivering an additional 50,000 dekatherms a day to our system in the Watertown area.

Niagara Mohawk's electrical transmission and distribution system is at once a source of pride and concern. We have the capability to supply energy to 3.5 million New Yorkers.

Requests for new service throughout our eight operating regions continue to increase, a sign of economic strength in our service territory. However, we must remain diligent in our efforts to maintain and upgrade our existing systems.

In 1990, we are proposing to fund a dedicated transmission and distribution maintenance program, applying the resources necessary to ensure our network remains reliable. We will target those areas of our infrastructure that have been particularly troublesome for immediate attention, and will establish a comprehensive schedule of regular maintenance for the entire system.

This will help us achieve our corporate goal of reducing the duration of customer interruptions, while increasing our service availability index, already at 99.98 percent for the past ten years. This represents the percentage of time service is delivered to all customers without interruption.

Nuclear productivity remains a critical priority for Niagara Mohawk. Our primary effort is to ensure maximum productivity from our two nuclear stations, providing low-cost energy to our system for years to come.

1989 proved to be a difficult and challenging year in meeting our primary short-term goal: the return to service of Nine Mile One.

Significant work has been completed during this extended outage to attempt to assure that with the plant's return to service it will be capable of providing many more years of safe operation.

In response to a Nuclear Regulatory Commission requirement, we developed a detailed Restart Action Plan that identified and analyzed the root causes of our difficulties at Nine Mile One and outlined the necessary corrective actions. After working closely with regulatory staff to refine the plan, it was approved by NRC officials on September 29, 1989.

A Readiness for Restart Report was submitted to the NRC in early September, representing a comprehensive evaluation of the effectiveness of the corrective actions contained in the Restart Action Plan. With this report, we now have satisfied the three requirements established by the NRC as part of its intense oversight of the Nine Mile One plant.

In January, Nine Mile One reached a significant milestone in the restart process, as plant operators completed the reloading of fuel in the reactor core in anticipation of NRC approval for resumed operations in the second quarter of 1990.

As we developed the Nine Mile One Restart Action Plan, we realized the need for improvement throughout our nuclear operations. That was the genesis of our Nuclear Improvement Program. Where the Restart Action Plan addresses the specific requirements for returning Nine Mile One to service, the Nuclear Improvement Program focuses on long-term improvements in achieving excellence throughout the Nuclear Division.

NUCLEAR GENERATION:

"Our success to date in completion of the requirements toward restart of Nine Mile One and the recent performance of Nine Mile Two are examples of the positive direction that our nuclear division is headed. Our goals and standard of performance are aimed at achieving excellence in nuclear operations, and not just mere compliance."

Lawrence Burkhardt, III
Executive Vice President
Nuclear Operations
September 15, 1989

Results for 1989 from Nine Mile Two also were mixed. Nagging operational and mechanical difficulties reduced the plant's overall availability and unfortunately drew attention away from the fact that, during the year, Nine Mile Two completed an operational run of 134 consecutive days in October, during which it achieved a capacity factor above 90 percent.

In July, we announced a new interim operating agreement for Nine Mile Two further defining the roles of the plant's owners and continuing our role as operator. Over the 18-month life of the agreement, the owners will explore alternative operating methods, including the formation of an operating company. The new agreement is significant in that it unifies and strengthens our co-owner relationship during this time of increased regulatory scrutiny of plant operations.

In 1990, we have scheduled a refueling for Nine Mile Two, and set a goal to operate the unit at a much-improved availability factor.

We faced other difficulties with respect to our nuclear operations during 1989 that cast additional shadows over our improvement efforts. In

July, 14 of 48 Nine Mile Two operators failed license requalification testing.

While we had a sufficient number of qualified operators to continue operation and all but one of the 14 were successfully retested, it pointed out a need to strengthen our training efforts, and we have initiated an action plan to correct such deficiencies. We are continuing an aggressive program to recruit highly qualified professionals to strengthen our management team in all areas of nuclear operations and engineering.

In August, an NRC inspection team conducted an investigation of the circumstances surrounding a 1981 spill of radioactive waste containers in a waste storage facility at Nine Mile One. The NRC concurred with our contention that at no time was the health and safety of the public or our employees endangered by the situation, but found that we may have committed two technical violations of regulations.

No determination has been made by regulators about what sanctions, if any, may be imposed against the company. Clean-up of the spill has started, and we will absorb any costs above amounts previously provided in rates.

Both nuclear units remain on the NRC's list of facilities requiring close regulatory monitoring. The intense level of scrutiny our nuclear operations have come under from our regulators is surpassed only by our own efforts at examination, analysis and improvement.

We embarked on the path of nuclear power production some 30 years ago as a buffer against sustained dependence on any single fuel source. Our recent difficulties in nuclear plant operations have overshadowed our success in achieving a diverse fuel mix.

Our goal for nuclear operations is to manage our plants to obtain the most value for customers and shareholders. To do this, we must maximize productivity and provide leadership that encourages our people to meet the highest standards.

Economic development is fundamental to the prosperity of Niagara Mohawk and the communities it serves. What better way, then, to stimulate economic growth than through a powerful coalition of private and public interests.

The Niagara Mohawk Power Corp./New York State Partnership established a framework in 1989 to enhance the business-attraction efforts of local, regional and state economic development entities. We have dedicated $4 million to the program, allowing the Partnership to concentrate on luring new businesses to upstate New York and to retaining jobs and expanding businesses in our service territory.

This initiative will improve coordination among economic development agencies and officials at all levels, while providing them with an effective new array of tools.

The models, methods, techniques and programs developed by the Partnership will be used to stimulate economic development throughout New York. The Partnership will concentrate on four key activities: an analysis of business opportunities, the identification of growth priorities, a follow-through on business development, and the delivery of targeted communications.

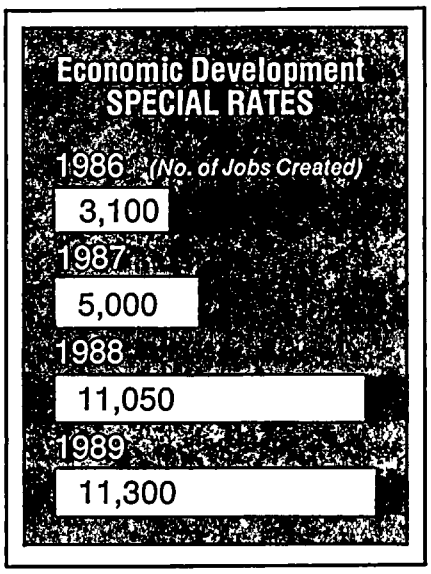
We believe there will be an increasing number of export opportunities and Canadian business expansion in New

York as a result of the ratification of the Free Trade Agreement between the United States and Canada. The Partnership also will install a statewide computer network to track economic development prospects and to manage other data vital to business growth.

While the Partnership offers exciting opportunities as it develops, we continue to have success in our economic development endeavors through the application of our three incentive programs.

First is the Economic Development Rider, offering businesses discounted rates for new or added electrical or gas load. Another is the Economic Development Zone Rider, with special rates for new or added load for businesses that relocate or expand in economically distressed localities throughout our service territory.

And finally, we offer the Economic Revitalization Incentive Rider to support financially distressed industries already located in our service territory. Thus far, the three programs have been used by some 172 businesses, contributing to the creation or retention of approximately 11,300 jobs.



Demand-side management: Late in 1989, Niagara Mohawk launched a major new incentive to promote energy efficiency among the more than 3.5 million people in its service territory.

Extensive research and development in the area of conservation and load management have yielded a menu of significant new programs that will help curb customers' growing appetite for electricity and could delay the need to construct large new generating stations in the future.

By intervening in the marketplace to influence the energy decisions its customers make, Niagara Mohawk is practicing what is known in the industry as "demand-side management." In other words, rather than simply supplying electricity to customers, DSM programs attempt to alter customers' demand for electricity.

And significantly, we joined with the Public Service Commission and other utilities in the state to devise and implement methods for recovering all demand-side management costs and fairly rewarding the companies' shareholders for their investment in conservation and load-management programs. The result: economic incentives that serve the best interests of shareholders and customers.

Demand-side management efforts now underway include the Residential Time-of-Use program, the Low-Cost Measures program and the Commercial and Industrial Lighting program. Additional programs will be brought to the public in 1990.

Each program is unique, targeted to specific populations and customer groups. The goal, however, is the same: to help our customers efficiently manage their use —and their cost—of energy.

In the Low-Cost Measures program, our residential cus-

tomers are being offered—free of charge—four important energy-saving devices: a low-flow shower head, water heater insulation, pipe wrap and an efficient light bulb.

Cash incentives are being offered to Commercial and Industrial Lighting program participants, who also benefit by significantly reducing their energy bills when they purchase high-efficiency fluorescent lamps and ballasts.

In December, we began requiring the 16,000 largest residential users of electricity to subscribe to special time-of-use rates, a key corporate goal. Under time-of-use rates, the price customers pay for electricity changes daily and seasonally, corresponding with the actual cost of electricity production.

If there was any question as to the need for such an effort, we need only remember this figure: 6,376. That is the number of megawatts demanded from our customers on December 21, 1989, an all-time company record achieved at least two years earlier than anyone had predicted.

DEMAND-SIDE MANAGEMENT:

"...Niagara Mohawk experts will play a much greater role in helping you, your clients and our customers use electricity as cost efficiently as possible. We see education as the key. Our objective is to extend the energy partnership all the way to the individual customer."

John M. Endries
President
April 24, 1989

Service excellence programs were developed and strengthened throughout 1989. But meeting the needs of our diverse customer base requires more than programs. People—Niagara Mohawk people—are at the heart of our commitment to providing excellent service.

We intensified our training associated with the "Think Like a Customer" program, now having reached more than 6,000 employees since its inception in 1987. Complaints to the Public Service Commission have dropped by about 16 percent since that year.

Regional "Managing the Customer Experience" teams were instrumental in examining and resolving customer service problems, with 23 separate recommendations already implemented. And in January, 1990, training began for an additional 4,000 members of our work force.

Niagara Mohawk has been a pacesetter in the implementation of company-initiated, as well as mandated, consumer service programs for many years. A wide range of individualized services are available for all classes of customer accounts.

To strengthen our capabilities, we created 55 new positions in critical customer-related functions. And since severe weather conditions or equipment problems often test a utility's ability to provide service, we increased our training of personnel and testing of emergency response procedures.

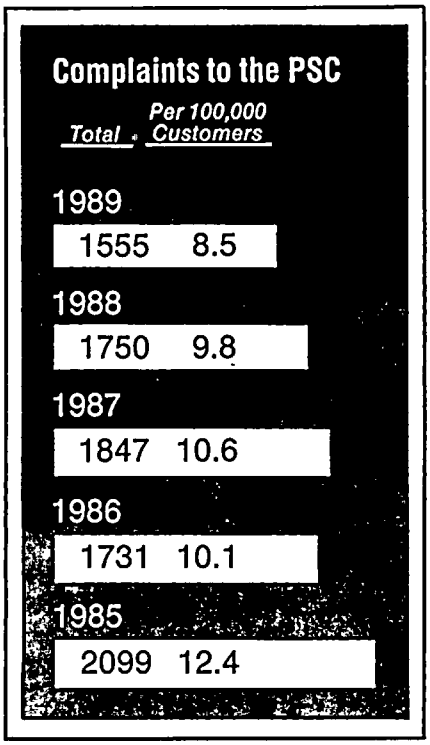
Service excellence requires that we reach out to customers, particularly those in need of special assistance. Our programs include special services for the elderly and the handicapped, and for those who have difficulty affording electric and gas service so vital to everyday living.

We note with pride that two of our programs were accorded national recognition in 1989. Our Gatekeeper pro-

gram trains customer-contact employees to be aware of conditions that could indicate an elderly person is in need of medical or social-service assistance. The Academic Enrichment program is part of the company's efforts to take an active role in supporting education in our service territory.

These programs were awarded Presidential Citations as part of the President's Citation Program for Private Sector Initiatives in a White House ceremony. Niagara Mohawk was one of very few companies in the nation to receive more than one award.

In 1990, Niagara Mohawk again will reach out with a new, comprehensive program designed to help low-income households better manage their energy usage and consequent costs. Known as "Power Partnerships," this program will include customer identification, household weatherization and energy education efforts for those who have the most difficulty in affording the most basic energy services.



Consumer programs can be successful only if the people conducting them care about their customers. Niagara Mohawk employees care not only about their customers, but about their communities as well.

A group of employees in Glens Falls donated the cash from an exceptional service award they had earned to victims of the devastating earthquake that rocked the San Francisco Bay area in the fall of 1989. The Nuclear Security department received an exceptional service award for its outstanding ratings during federal regulatory inspections. That award was donated to three area charities. And two Buffalo area service employees risked their lives to save several children from a burning house.

These are just three recent examples of Niagara Mohawk people helping others and the communities they serve. These accounts are indicative of the qualities inherent in our people.

Diversification: While we regain financial strength and stability in our regulated core business, we will be assisted by the growing financial contributions from diversification efforts at our two major subsidiaries, Opinac Energy and HYDRA-CO. Both have proven to be sound investments for Niagara Mohawk.

Opinac, our Canadian subsidiary, is in the midst of expansion, showing steady increases in earnings, cash flow and oil and natural gas production.

It operates two distinct divisions. Opinac Exploration Limited is the oil and gas exploration and production division in Calgary, while Canadian Niagara Power generates

electricity at its Niagara Falls, Ontario hydro plant for the wholesale market and for its distribution system in Fort Erie, Ontario.

A steady flow of earnings from the utility division has enabled Opinac to build a strong portfolio of energy-related investments, while steadily increasing its own drilling and production activities.

In 1990, Opinac's average daily production is expected to reach 2,200 barrels of oil and 78 million cubic feet of gas, a nearly ten-fold increase in just three years.

In November, Canadian Niagara Power began supplying electricity under contract to the City of Cornwall, Ontario, and expects increased demand in the Fort Erie market as a result of the Free Trade Agreement between the U.S. and Canada.

HYDRA-CO, too, has been a valuable asset. Formed in 1981, its primary objective is to develop and own principal

HYDRA·CO

stakes in a diversified portfolio of independent power projects with strong growth and earnings potential. Its track record is excellent.

With a geographic portfolio of projects from Maine to California, HYDRA-CO is involved in the broad spectrum

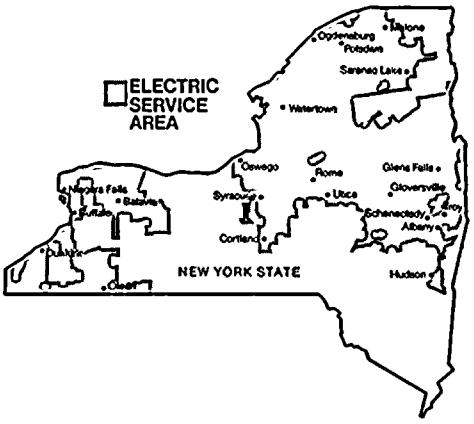
OPINAC ENERGY

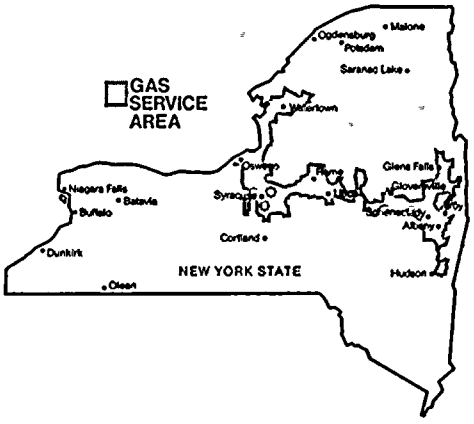
of co-generation and independent production activities; from agricultural biomass and wood waste to coal and natural gas-fired, from hydroelectric to wind power.

In 1989, the power production company brought on line some 149 megawatts of power, bringing its total project capability to 322 megawatts.

Under construction and scheduled for operation in 1990 and 1991 are six more facilities with a combined capacity of nearly 262 megawatts. In all, HYDRA-CO is involved in projects with total assets of more than $730 million.

We expect that Opinac and HYDRA-CO will continue to flourish in the new decade. As we achieve greater financial strength, we will examine other legitimate opportunities for additional diversification in areas related to our core business.





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.

	1989	1988	1987	1986	1985
Operations: *(000's)*					
Operating revenues	$2,906,043	$2,800,453	$2,623,430	$2,660,319	$2,694,940
Income before cumulative effect of accounting change	150,783	208,814	57,786	397,865	411,430
Cumulative effect on prior years of adoption of SFAS No. 90	—	—	(615,000)	—	—
Net income (loss)	150,783	208,814	(557,214)	397,865	411,430
Proforma balance available for common stock —giving effect to the retroactive application of SFAS No. 90	—	—	5,769	16,048	64,871
Common stock data:					
Book value per share at year end	$14.07	$13.87	$13.82	$20.23	$19.61
Market price at year end	14⅜	13	12	16¾	20½
Ratio of market price to book value at year end	102.2%	93.7%	86.8%	82.8%	104.5%
Dividend yield at year end	0.0%	9.2%	10.0%	12.4%	10.1%
Earnings per average common share before cumulative effect of accounting change	$ .78	$ 1.21	$ .05	$ 2.71	$ 2.88
Cumulative effect on prior years of adoption of SFAS No. 90 per average common share	—	—	(4.83)	—	—
Earnings per average common share	.78	1.21	(4.78)	2.71	2.88
Proforma earnings per average common share —giving effect to the retroactive application of SFAS No. 90	—	—	.05	.13	.53
Rate of return on common equity	5.6%	8.7%	12.7%*	13.6%	15.0%
Dividends paid per common share	$ .60	$ 1.20	$ 1.64	$ 2.08	$ 2.06
Dividend payout ratio	76.9%	99.2%	—	76.8%	71.5%
Capitalization: *(000's)*					
Common equity	$1,914,531	$1,881,394	$1,781,518	$2,571,491	$2,488,620
Non-redeemable preferred stock	290,000	290,000	290,000	290,000	290,000
Redeemable preferred stock	267,530	295,510	355,490	347,470	379,850
Long-term debt	3,249,328	2,995,748	2,903,921	2,799,605	2,643,094
Total	5,721,389	5,462,652	5,330,929	6,008,566	5,801,564
First mortgage bonds maturing within one year	50,000	33,000	50,000	50,000	30,000
Total	$5,771,389	$5,495,652	$5,380,929	$6,058,566	$5,831,564
Capitalization ratios: *(including first mortgage bonds maturing within one year):*					
Common stock equity	33.2%	34.2%	33.1%	42.5%	42.7%
Preferred stock	9.6	10.7	12.0	10.5	11.5
Long-term debt	57.2	55.1	54.9	47.0	45.8
Financial ratios:					
Ratio of earnings to fixed charges	1.71	2.10	1.65**	2.98	3.07
Ratio of earnings to fixed charges without AFC	1.66	2.06	1.54**	2.42	2.37
Ratio of AFC to balance available for common stock	18.3%	6.9%	—	48.2%	53.2%
Ratio of earnings to fixed charges and preferred stock dividends	1.41	1.67	1.04**	2.35	2.36
Proforma Ratios—giving effect to the retroactive application of SFAS No. 90:					
Earnings to fixed charges	—	—	1.65	1.28	1.40
Earnings to fixed charges and preferred stock dividends	—	—	1.04	1.05	1.17
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	36.5%	34.6%	35.6%	38.0%	43.4%
Maintenance, depreciation and amortization	14.4	15.1	12.1	11.4	10.9
Total taxes	15.3	16.1	16.7	18.1	15.7
Operating income	14.2	17.0	18.5	16.6	15.3
Balance available for common stock	3.6	5.7	—	12.9	13.1
Miscellaneous: *(000's)*					
Gross additions to utility plant	$ 411,887	$ 366,142	$ 457,109	$ 784,137	$ 781,064
Total utility plant	8,324,112	7,967,625	7,691,069	8,445,993	7,640,905
Accumulated depreciation and amortization	2,283,307	2,090,170	1,913,687	1,763,443	1,629,437
Total assets	7,575,093	7,076,041	6,794,098	7,611,203	7,013,837

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

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

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

The Company has faced, and continues to face, a number of significant challenges in its attempt to strengthen its financial integrity which was severely eroded by the 1987 write-off of disallowed Nine Mile Point Nuclear Station Unit No. 2 (Unit 2) costs. The more significant challenges stem from problems associated with nuclear operations, specifically the continuing outage at Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) and the performance of Unit 2 since it commenced commercial operation in April 1988.

While these problems have had a detrimental impact on the Company's recent historical earnings and its ability to declare common stock dividends, there are a number of emerging state regulatory developments and possible structural changes in the electric and gas industries which may have a much broader and longer-lasting effect on the Company's operations and the environment in which it conducts business. A number of these issues are discussed at greater length below as they relate to the Company's agreement dated August 31, 1989 (the 1989 Agreement) with the Staff of the Public Service Commission (PSC Staff), the New York Consumer Protection Board, the New York Attorney General and Multiple Intervenors. The Company believes this agreement marks the beginning of an improved relationship with its regulators.

Other important emerging issues include questions of open access to the Company's transmission facilities by other parties, and vice versa, initiatives relating to "incentive regulation" which may ultimately affect how the consequences of regulation are reflected in the Company's financial statements and a combination of demand side management (conservation) and bidding programs that will possibly eliminate the Company's need to construct base load generating facilities into the next century, while still permitting it to meet increasing demand in its service territory.

The Company's ability to return to financial strength is dependent upon its ability to appropriately respond to these challenges and to anticipate other emerging issues. A key element of the 1989 Agreement is the conduct by the Company, with participation by the New York Public Service Commission (PSC), of a self-assessment process with the overall objective of placing the Company in a position to manage itself more effectively and efficiently. As discussed below, the Company's near-term financial stability, as well as its success in the future, will be driven by the self-assessment process.

RESULTS OF OPERATIONS

Earnings for 1989 of $.78 per share (representing a decrease of 36% from 1988 earnings of $1.21 per share) reflect a number of regulatory agreements entered into by the Company during 1988 and 1989, the costs associated with the continuing Unit 1 outage and the costs of new programs that had not, because of changing conditions, been anticipated within the regulatory agreements.

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.

Under the Stipulation Agreement, the Company agreed to, among other things, no increase in base rates for electric service through June 30, 1990, while at the same time refunding $14 million to ratepayers over the twelve-month period ended June 30, 1989. The Company has and will be allowed to reflect in electric operating revenue a total of approximately $102 million in unbilled electric revenues, representing non-cash earnings, to offset otherwise required increases in specified costs over the two-year period covered by the Stipulation Agreement and to provide substantial recovery of the Company's investment in the Lake Erie Generating Station Project. Other substantive provisions included establishment, for the Company's ratemaking purposes, of April 5, 1988 as the commercial operation date for Unit 2. The Company was permitted to defer all costs of operating Unit 2 from April 5, 1988 to June 30, 1988, and to amortize and recover such costs over the life of Unit 2. The Company recorded the effects of the refund, the write-off of the unrecovered portion of the Lake Erie Generating Station Project costs, the accrual of unbilled revenues and other provisions of the Stipulation Agreement in 1988, resulting in a net reduction in earnings per share of $.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.

The Company entered into an interim relief agreement (the "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 in replacement power costs through the fuel adjustment clause mechanism, commencing with the fuel cost month of January 1989, until the earlier of the restart of Unit 1 or June 30, 1989. This reduced the Company's cash flow through the agreement period by approximately $40.7 million.

The Company deferred, for regulatory purposes only, replacement power cost revenues associated with the Interim Relief Agreement 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 precluded the recording of these revenues for financial reporting purposes, which reduced earnings per share during 1989 by approximately $.20.

Unit 1 did not return to service by June 30, 1989 and the Interim Relief Agreement expired by its terms. The parties to the Interim Relief Agreement, however, were free to seek an extension of interim relief. Pursuant to the 1989 Agreement, (See Note 11 of Notes to Consolidated Financial Statements for further discussion) the parties thereto, including the PSC, agreed to refrain from filing any request for cessation of the flow-through to customers of Unit 1 replacement power costs so long as the 1989 Agreement is in effect; however, such costs collected remain subject to

the Unit 1 outage prudence investigation.

Based upon management's current assessment of the facts and circumstances surrounding the Unit 1 outage, the Company has deferred and recovered through the fuel adjustment clause mechanism, the replacement power costs associated with the fuel cost months of July through December 1989, and anticipates that it will be able to continue to do so through the restart of Unit 1. However, the Company's ability to record future replacement power costs recovered through the fuel adjustment clause mechanism as revenues for financial reporting purposes is subject to change as facts and circumstances surrounding the investigation of the Unit 1 outage change. Inability to record these revenues could impact the Company's attainment of the 1.60 times interest coverage provided for in the 1989 Agreement (See Note 11 of Notes to Consolidated Financial Statements).

In addition to the negative earnings impact associated with the Interim Relief Agreement, the Company estimates that it has also absorbed approximately $17 million of Unit 1 replacement power costs during the course of the outage through the sharing provisions of the fuel adjustment clause mechanism, for a total amount absorbed of approximately $58 million. Based upon assumptions utilized in determining the amount of replacement power costs occasioned by the Unit 1 outage, the Company estimates that it has collected up to $154 million of replacement power costs from ratepayers. The Company also estimates that it has absorbed approximately $97 million ($69 million in 1989) of incremental Unit 1 operating and maintenance costs, occasioned by the outage, in excess of amounts provided for in the ratesetting process.

Replacement power costs associated with the Unit 1 outage averaged approximately $332 thousand per day through December 31, 1989, as determined using a New York Power Pool/Canadian supplier average cost per kilowatt-hour. The precise amount of daily replacement power costs incurred and to be incurred is dependent upon seasonal factors, relative demand and availability of capacity, as well as, assumptions utilized in estimating replacement power costs incurred as occasioned by the outage.

As a result of its deteriorating financial condition occasioned by the effects of the agreements discussed above and increasing expenses relating to the Unit 1 outage and new programs (the costs of which were not anticipated in the Stipulation Agreement), the Company investigated a number of options to improve its financial condition.

On August 31, 1989, the Company, the PSC Staff, the New York Consumer Protection Board, the New York Attorney General and Multiple Intervenors entered into the 1989 Agreement which establishes a framework within which the Company's current and future financial condition can be addressed while also providing a process for the ultimate resolution of numerous regulatory issues currently faced by the Company. In an order issued on October 20, 1989, the PSC approved the 1989 Agreement.

The 1989 Agreement addresses the Company's current financial condition by permitting the Company to attain a minimum monthly interest coverage level, without Allowance for Funds Used During Construction (AFC), of 1.60 times through the end of 1990. This minimum coverage level will be maintained by the deferral of expenses subject to the exclusion of extraordinary losses, if any, that may occur during the period. Through December 31, 1989, the Company, in order to maintain the minimum coverage of 1.60 times, has deferred approximately $13.8 million of operating expenses for future recovery. In addition, during the last six months of 1990, minimum cash coverage of 1.60 times (without AFC and non-cash items) is intended to be maintained, if necessary, through a surcharge to customers equivalent to available gross margin from transmission and resale revenues. The ability of the Company to achieve the cash coverage target may be limited by the availability of such transmission and resale gross margin during the last six months of 1990 and the Company's ability to achieve forecasted sales and expense levels utilized in the 1989 Agreement. The cash surcharge under this provision of the 1989 Agreement will serve to reduce expense deferrals which would otherwise be permitted to achieve minimum coverage or target coverage (as described below) under the 1989 Agreement. The Company believes that the provisions of the 1989 Agreement, including the targeted minimum cash coverage established for the last six months of 1990, may enable it to maintain the investment grade status of its senior securities; however, no such assurance can be provided. (See "Liquidity and Capital Resources" below for a discussion of the Company's securities ratings at December 31, 1989.)

In accordance with the 1989 Agreement, the Company is undertaking a comprehensive self-assessment of the efficiency and effectiveness of its organization and management. On December 15, 1989, the Company submitted to the PSC a work plan describing the self-assessment approach, including a schedule for its completion. The work plan includes a mid-course milestone in the form of a report on the progress and status of the self-assessment effort, such report is to be completed on or before May 1, 1990. The Company is required to submit, no later than November 15, 1990, a report summarizing the results of the self-assessment and provide implementation plans addressing the issues identified. The development of the work plan and the self-assessment process will serve as a benchmark based on which the Company will be permitted the opportunity to achieve targeted interest coverage levels higher than 1.60 times interest charges (without AFC) during 1990. With the acceptance of the work plan by the PSC on December 29, 1989, the Company is now permitted to defer up to $23 million of expenses for future recovery in an effort to achieve an interest coverage level (without AFC) of 1.75 times for the first six months of 1990. If the Company successfully completes the mid-course milestone included in the work plan by May 1, 1990, the Company will be permitted to defer additional expenses for future recovery to provide an interest coverage level of 1.85 times, also without AFC, for the last six months of 1990. However, there is no assurance, even if the Company successfully completes the mid-course milestone, that it will achieve the indicated targeted coverage levels since such levels are dependent on actual results of operations and exclude extraordinary items. Moreover, the other parties to the 1989 Agreement have the right to contest before the PSC whether the Company is reasonably carrying out the self-assessment process, and thus whether the Company has successfully achieved the mid-course milestone.

Based upon current estimates of earnings for 1990, the Company does not believe that it will attain the interest coverage level (without AFC) of 1.75 times during the first six months of 1990. The shortfall is primarily related to forecasted operating expenses in excess of amounts utilized in the 1989 Agreement. The Company presently anticipates that it will achieve the 1.85 times interest coverage level (without AFC) during the last six months of 1990.

As a result of a number of factors, including uncertainties as to future rate relief, the restart of Unit 1 and the status of several outstanding regulatory proceedings, the Board of Directors, on August 31, 1989, determined to omit the

third quarter common stock dividend. Pursuant to the 1989 Agreement, if the Company resumes payment of common stock dividends prior to Unit 1 being fully returned to service (and achieving an average 75% capacity factor for a period of thirty consecutive days) any other party to the 1989 Agreement may withdraw therefrom and recommence litigation of the rate case discussed below and other regulatory proceedings covered by the 1989 Agreement. The Company can provide no assurance that when Unit 1 has returned to service its Board of Directors will thereupon determine to resume dividend payments or as to the level at which they might be resumed. Other factors to be considered may include the status of future rate relief and the resolution of outstanding regulatory proceedings as disclosed in the 1989 Agreement.

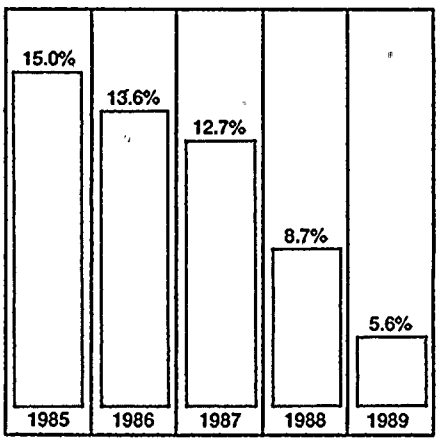
In August 1989, the Company filed an application with the PSC requesting an increase in electric and gas rates which would, if granted, produce additional revenues of $369.6 million for the year ending June 30, 1991. In December 1989, the application was updated and revised to $344.5 million. The PSC would have been required to decide the case by July 4, 1990; however, pursuant to the 1989 Agreement, the Company extended the period within which a decision is required for this rate request to no later than March 1, 1991. In the event the PSC does not establish permanent rates by January 1, 1991, temporary rates will be put in effect as of that date, with permanent rates to become effective no later than March 1, 1991. The effect of this extension is to continue through December 31, 1990 the base rates established in the 1988 Stipulation Agreement. The parties to the 1989 Agreement have agreed to negotiate a multi-year rate plan, including incentive return mechanisms, with the objective of improving the Company's financial condition and the predictability of future rates. Irrespective of these negotiations, the parties have agreed that any costs deferred pursuant to the maintenance of the specified interest coverage targets discussed above or other costs deferred pursuant to the 1989 Agreement, will be recovered in rates, in each case plus carrying charges, over a period no longer than three years beginning January 1, 1991. Recovery of the expense deferrals is subject to an annual cap equivalent to two percent of operating revenues (approximately $50 million per year). The total amount of deferred costs to be recovered is not limited. The Company anticipates that, based on current forecasts, total costs deferred in order to maintain specified interest coverage targets discussed above, net of available cash surcharges equivalent to gross margin from transmission and resale revenues, will not exceed $100 million including carrying charges, with the preponderance of such deferrals expected to occur in the last half of 1990. The Company can provide no assurance as to the outcome of the rate plan negotiations, the level and quality of earnings that may ultimately be authorized or the Company's ability to earn the authorized equity return established.

There are a number of outstanding regulatory issues affecting the Company, including the Unit 1 prudence investigation, Unit 2 Settlement cap issues, Unit 2 contractor litigation issues and Unit 2 operating prudence issues. A goal of the 1989 Agreement is the ultimate resolution of these issues, either by negotiation or by the PSC if negotiations are not conclusive. The PSC must render a final decision on the Company's rate request no later than March 1, 1991. The Company can provide no assurance as to the outcome of the negotiations or the PSC's approval thereof, or the impact that the resolution of these issues will have on the Company's financial condition or results of operations. The Company and cotenant companies are actively negotiating Unit 2 Settlement cap, contractor litigation and operating prudence issues. An "agreement-in-principle" has been reached with respect to these and other Unit 2 issues which would close all issues of prudence with respect to the construction cost of Unit 2 and operations through January 19, 1990 and allocate litigation proceeds, net of litigation costs, equally between ratepayers and shareholders (See Note 10 of Notes to Consolidated Financial Statements).

The Company has been studying the advantages and disadvantages of continuing the operation of Unit 1. Pursuant to the 1989 Agreement, the Company will further develop the study in good faith consultation with the parties to the 1989 Agreement and submit it to the PSC no later than February 28, 1990. The Company will also submit to the PSC and provide to the parties to the 1989 Agreement, on or before June 1, 1990, a study of the advantages and disadvantages of a separation, sale or other action with respect to the Company's gas business, and further develop that analysis in cooperation with the PSC Staff. The Company is unable to predict the results of these studies, what action may be initiated based upon such results or the impact that any such actions will have on the Company's financial condition or results of operations.

In 1989, the Company achieved a 5.6% return on common equity as compared with 8.7% in 1988 and 12.7% in 1987 (excluding the Unit 2 write-off). Although no authorized return on equity was established in the 1988 two-year Stipulation Agreement, the Company had anticipated a return on equity of approximately 9.4% in 1989 and 10% in 1988. The authorized return on equity at December 31, 1987 was 13.0%. The return on equity for 1990, while based upon certain assumptions that cannot be predicted with accuracy, is expected to be higher than the actual earned return on equity for 1989 as a consequence of, among other things, the anticipated return to service of Unit 1 and certain provisions of the 1989 Agreement which establish minimum and target interest coverage (without AFC) levels during 1990. However, the expectations for 1990 do not reflect the impact, if any, of the resolution of the outstanding regulatory issues referenced in the 1989 Agreement. As a result of deferrals utilized in an effort to achieve the target coverage levels, non-cash earnings will represent in excess of 75% of expected earnings available to Common Stockholders, as compared to 47% in 1989. The deferred costs are to be recovered generally over no longer than a three-year period beginning January 1, 1991, decreasing the percentage of non-cash earnings during that period. (See Note 11. Rates and Regulatory Matters—1989 Agreement.)

EARNED RATE OF RETURN ON COMMON EQUITY



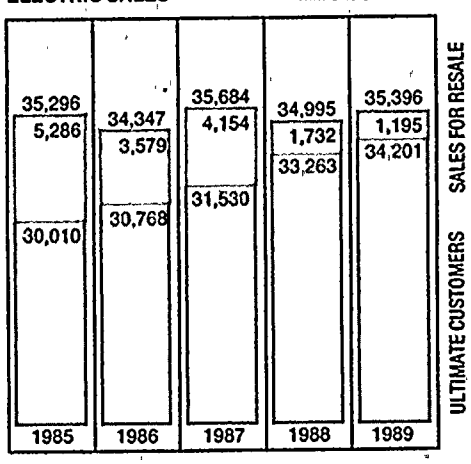
The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1989. It may not be indicative of future operations or earnings particularly in light of the 1989

Agreement. 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 $286.8 million or 13.5% 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 effective in 1987, fuel adjustment clause revenues, the recording of unbilled electric revenues in accordance with the Stipulation Agreement and increased miscellaneous revenues, offset in part by decreased sales to other electric systems, as indicated in the table below:

Electric revenues	Increase (decrease) from prior year *In millions of dollars* 1989	1988	1987	Total
Sales to ultimate consumers	$ 51.1	$ 82.0	$ 43.4	$176.5
Increase in base rates	—	12.9	49.7	62.6
Fuel and purchased power cost revenues	61.0	39.8	(53.8)	47.0
Sales to other electric systems	(2.2)	(57.8)	22.2	(37.8)
Unbilled electric revenues	(39.8)	62.5	—	22.7
Miscellaneous operating revenues	4.8	34.1	(23.1)	15.8
	$ 74.9	$173.5	$ 38.4	$286.8

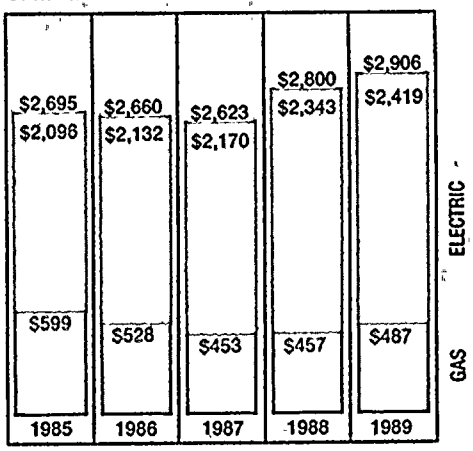
ELECTRIC SALES



Changes in fuel and purchased 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 1988 earnings unbilled revenues in an amount equal to the revenue required to amortize $39 million of the Company's investment in the discontinued Lake Erie Generating Station and to recoup other specified costs. Additional amounts of unbilled electric revenues were amortized in 1989 to offset other specified costs. Therefore the effect of accrual of unbilled electric revenues on net operating income was minimal. Included in 1988 and 1989 fuel and purchased power cost revenues are replacement power costs associated with the Unit 1 outage, however, such revenues in 1989 reflect a reduction of $40.7 million relating to the effects of the Interim Relief Agreement.

Electric kilowatt-hour sales were 35.4 billion in 1989, an increase of 1.1% from 1988 but a decrease of 0.8% from 1987. The 1989 increase reflects increased sales in most customer classifications, partly offset by a continued 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 44). The Company expects moderate weather-adjusted growth in sales to ultimate consumers in 1990. Details of the changes in electric revenues and kilowatt-hour sales by customer group are highlighted in the table below:

TOTAL ELECTRIC AND GAS OPERATING REVENUES



Class of service	1989 % of Electric Revenues	%Increase (decrease) from prior year 1989 Revenues	1989 Sales	1988 Revenues	1988 Sales	1987 Revenues	1987 Sales
Residential	34.8%	4.6%	2.6%	9.0%	4.6%	5.2%	3.2%
Commercial	36.1	5.6	2.2	5.7	4.3	2.1	3.3
Industrial	20.1	6.1	3.7	5.2	7.5	(3.0)	1.1
Municipal service	1.8	2.6	(3.8)	1.5	0.8	(1.0)	0.4
Total to ultimate consumers	92.8	5.3	2.8	6.7	5.5	2.0	2.5
Other electric systems	2.4	(3.6)	(31.0)	(49.0)	(58.3)	23.2	16.1
Miscellaneous	4.8	(23.2)	—	179.2	—	(30.0)	—
Total	100.0%	3.2%	1.1%	8.0%	(1.9)%	1.8%	3.9%

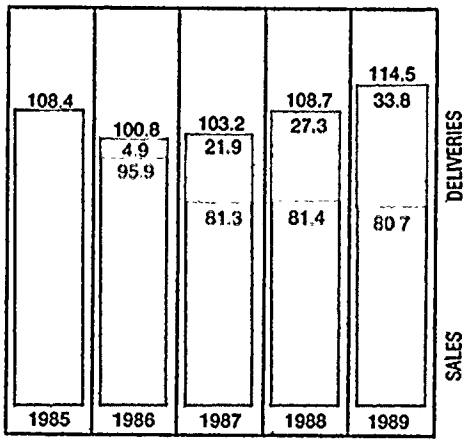
On March 13, 1987, the PSC approved a 4.0% electric rate increase to provide the Company additional annual revenues of $74,898,000 based on (i) forecast sales for the twelve months ended March 31, 1988, (ii) a 13.0% return on equity, and (iii) the inclusion of $1.625 billion of construction work-in-progress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

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 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 1989 Agreement discussed above, the base rate freeze has been extended to December 31, 1990; and rate adjustments to be effective January 1, 1991 will be determined in the latter part of 1990.

Gas revenues decreased $41.1 million or 7.8% over the three-year period. As shown by the table below, this decrease is primarily attributable to 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.

GAS SALES

Millions of dekatherms



Gas revenues	Increase (decrease) from prior year In millions of dollars 1989	1988	1987	Total
Purchased gas adjustment clause revenues	$ 23.5	$ (6.2)	$ (12.0)	$ 5.3
Increase (decrease) in residential sales	11.6	18.9	(8.8)	21.7
Decrease in commercial and industrial sales	(7.4)	(15.1)	(61.9)	(84.4)
Transportation of customer-owned gas	6.0	2.3	9.3	17.6
Miscellaneous operating revenues	(3.0)	3.6	(1.9)	(1.3)
	$ 30.7	$ 3.5	$ (75.3)	$ (41.1)

Gas sales, excluding transportation of customer-owned gas, were 80.7 million dekatherms in 1989, a 0.9% decrease from 1988 (See Electric and Gas Statistics—Gas Sales appearing on page 44). The decrease for 1989 includes a 3.6% increase in sales in the residential class reflecting a combination of weather-related sales and load growth, offset by a 3.3% decrease in sales in the commercial class and a 38.9% decrease in sales in the industrial class as a result of competition from oil and the ability of customers to purchase gas directly from producers. The Company transported 33.8 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	1989 % of Gas Revenues	% Increase (decrease) from prior year 1989 Revenues	1989 Sales	1988 Revenues	1988 Sales	1987 Revenues	1987 Sales
Residential	65.2%	9.9%	3.6%	3.2%	6.3%	(5.6)%	(2.8)%
Commercial	25.8	5.0	(3.3)	(1.0)	1.8	(15.2)	(13.6)
Industrial	2.5	(35.2)	(38.9)	(36.1)	(41.0)	(56.6)	(53.5)
Total to ultimate consumers	93.5	6.5	(0.8)	(0.7)	0.6	(15.2)	(14.5)
Other gas systems	1.9	(1.0)	(6.4)	6.4	(13.8)	(38.4)	(32.8)
Transportation of customer-owned gas	4.1	43.3	24.0	19.8	24.6	414.8	349.1
Miscellaneous	0.5	(54.5)	—	189.9	—	(49.7)	—
Total	100.0%	6.7%	5.3%	0.8%	5.3%	(14.2)%	2.3%

In January 1988, the PSC approved a gas rate settlement proposed by the Company and interested parties, which maintains 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. As a result of the 1989 Agreement discussed above, the Company extended the gas base rate freeze through December 31, 1990, and rate adjustments to be effective January 1, 1991 are expected to be determined in the latter part of 1990.

In 1989, electric fuel and purchased power costs increased to $771 million from $704 million in 1988 and $666 million in 1987. The increase in 1989 is the result of a $106.9 million increase in fuel and purchased power costs incurred offset by a $39.7 million net decrease in costs deferred and recovered through the operation of the fuel adjustment clause. Although generation and kilowatt-hour purchases increased only .4%, fuel and purchased power costs incurred increased 14.8% because of the use of higher cost fossil-fired generation and higher priced purchased power to replace nuclear generation due to outages at Units 1 and 2 during 1988 and 1989 (See Electric and Gas Statistics—Electricity Generated and Purchased appearing on page 44).

The total cost of gas purchased increased 8.9% in 1989, after having decreased 1.1% in 1988, and 20.8% in 1987. The increase for 1989 is the result of a 2.7% increase in dekatherms purchased to meet customer demand coupled with higher rates charged by the Company's suppliers and an increase in purchased gas costs recognized and recovered through the purchased gas adjustment clause. In 1989, 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 increased to $3.39 in 1989 from $3.19 in 1988 and $3.27 in 1987.

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. The Company has absorbed $13.3, $21.4, and $3.6 million for each of the three years ended December 31, 1989, 1988 and 1987, respectively. Absorbed costs in 1988 exceeded $15 million due to the timing of rate years and of variances from fuel targets. In December 1987, the PSC established a generic proceeding to examine the operation of the existing fuel adjustment clause, including whether the fuel adjustment clause should continue. The Company is unable to predict the outcome of this proceeding.

Other operation and maintenance expenses increased $95.4 million or 14.3% in 1989, after having increased 23.2% in 1988 and decreased slightly in 1987. 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. The increase in other operation and maintenance expense was partly offset by the deferral of (i) nuclear improvement costs of approximately $7.1 million included in Other Deferred Debits and (ii) $13.8 million of expenses to meet the 1.60 minimum interest coverage ratio, excluding AFC, pursuant to the 1989 Agreement and included in Deferred Operating Expenses. In 1990, the Company anticipates that expense deferrals to achieve target coverages, after application of cash surcharges, will approximate $80 million.

Depreciation and amortization expense for 1989 increased 15.7% over 1988 and 15.6% over 1987, principally from Unit 2 becoming commercial.

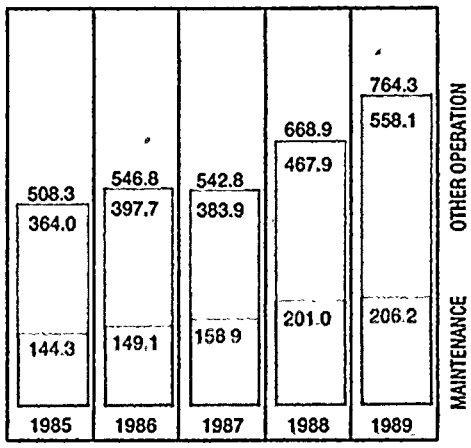
Net Federal and foreign income taxes for 1989 decreased as a result of a reduction in taxable income. The increase in taxes other than income taxes in the three-year period is due principally to higher property taxes resulting from property additions and the reflection of Unit 2 taxes that are now being charged to operations.

Other income and deductions, excluding Federal income taxes, increased $36.6 million from 1988. This increase is primarily the result of the recording in 1988 of a $14 million refund to customers and the write-off of unrecovered Lake Erie Generating Station costs of approximately $6 million, in accordance with the Stipulation Agreement, coupled with increased AFC, increased 1989 subsidiary earnings (principally Opinac) and gains on the sales of certain investments in 1989.

Net interest charges increased $31.4 million in 1989, primarily the result of the issuance of $300 million in First Mortgage Bonds, $100 million Medium-Term Notes, $69.8 million NYSERDA Promissory Notes and increased costs related to short-term borrowing. Dividends on preferred stock decreased $3.9 million in 1989 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, changed to 9.18% and 7.71%, respectively, in 1989, from 8.92% and 7.90%, respectively, in 1988.

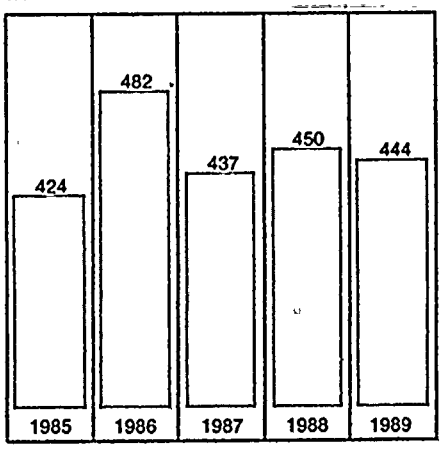
MAINTENANCE AND OTHER OPERATION EXPENSE

Millions of dollars



TOTAL TAXES INCLUDING INCOME TAXES

Millions of dollars



Effects of Changing Prices. The rate of inflation was below 5% in 1989. 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 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 1989 dollars:

	1989	1988	1987
Operating Revenues ($000's)	$2,906,043	$2,935,386	$2,863,603
Gain from decline in purchasing power on net amounts owed ($000's)	$ 163,729	$ 152,116	$ 160,923
Per Common Share:			
Cash dividends declared	$ .60	$ 1.26	$ 1.79
Market price at year end	$ 14.38	$ 13.63	$ 13.10
Average Consumer Price Index	124.0	118.3	113.6

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Financial Position. The Company's capital structure and earnings base has been negatively impacted by the financial effects of the 1987 write-off of Unit 2's disallowed costs, the continued Unit 1 outage and related Interim Relief Agreement. The capital structure at December 31, 1989 was 57.2% long-term debt, 9.6% preferred stock and 33.2% common equity as compared to 55.1%, 10.7% and 34.2%, respectively, at December 31, 1988 and 54.9%, 12.0% and 33.1%, respectively, at December 31, 1987. As a result of a number of factors, including the effects of the Unit 1 outage and related Interim Relief Agreement, the impact of the 1988 Stipulation Agreement, which, because of changing conditions did not provide for the costs of a number of programs the Company is now incurring, and the reliance on debt financing, the Company has been unable to improve its capital structure. As discussed further below, the Company is considering other forms of financing in 1990 to improve its capital structure. Book value of the common stock was $14.07 per share at December 31, 1989 as compared to $13.87 per share at December 31, 1988 and $13.82 per share at December 31, 1987; the increase is primarily attributable to the omission of the third and fourth quarter 1989 common stock dividends.

The ratio of earnings to fixed charges for 1989 was 1.71. This is compared to the 1988 ratio of 2.10. The ratio in 1987 was 1.65 (excluding the cumulative effect of adoption of SFAS 90) which was negatively impacted by the 1987 Unit 2 write-off. The 1989 ratio of earnings to fixed charges reflects the effects of the 1989 Agreement, which provided for near-term financial stabilization while establishing a framework for resolving regulatory and financial issues facing the Company. A key aspect of this financial stabilization was the establishment of minimum and target interest coverage levels (without AFC) in 1989 and 1990 as discussed at greater length under Results of Operations above. In order to maintain a minimum interest coverage level of 1.60 (without AFC) through 1989, the Company deferred $13.8 million of expenses for future recovery.

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 an annual level of $1.20 per share. On August 31, 1989, the Board of Directors, after considering the uncertainties facing the Company, including the level and timing of future rate relief, the restart of Unit 1, and the risks associated with a number of ongoing regulatory proceedings, determined to omit the third quarter common stock dividend. Resumption of payment of the common stock dividend will depend on the resolution of issues affecting the long-range financial condition of the Company, including the return to service of Unit 1 and the effect, if any, of such resumption of common stock dividends on the 1989 Agreement, as discussed in Note 11 of Notes to Consolidated Financial Statements. (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. Total capital needs have decreased since 1987 as Unit 2 then approached completion and as budgeted construction expenditures were curtailed. Annual expenditures for the years 1987-1989 for construction and nuclear fuel, including related AFC and overheads capitalized, were $457.1 million, $366.1 million and $411.9 million, respectively. Capital needs have also been affected by the extended Unit 1 outage and the suspension of the common stock dividend.

The 1990 estimate for construction additions, overheads capitalized and nuclear fuel, excluding AFC, is approximately $442 million, of which approximately 80% 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 $233 million to the Company's capital requirements, for a total of $675 million. Current estimates of total capital re-

quirements for the years 1991-1994 are $703 million, $675 million, $625 million and $658 million, respectively. Such estimates take into consideration, among other things, the 1989 Agreement and the extension of the outage at Unit 1 through the second quarter of 1990 and resumption of the common stock dividend in 1991, which is dependent upon a number of factors discussed above under "Financial Position". Future capital requirements rely on life-extension of the Company's existing facilities, the competitive bidding procedures in New York State for independent power production to satisfy future capacity requirements and demand-side management. The Company recently requested bids for 350 MW of electric capacity to be in-service by late 1994. Therefore, the Company's future capital requirements do not include any current plans by the Company to construct new base load generating facilities. Although peak electric load continues to increase in the Northeast, exacerbating concerns over available capacity, the Company believes it should be able to meet its growth in the 1990's through its bidding program, existing independent power producers' contracts and demand-side management programs.

Considered within the Company's future capital requirements are plans to construct, in 1990-1991, a $21 million gas pipeline across the St. Lawrence River to import Canadian gas supplies. However, the Canadian National Energy Board turned down an application from the Canadian supplier to export gas, which may jeopardize the project. The Company has appealed this decision. The primary objective of the pipeline is to improve the strategic diversity of the Company's gas supply, and as such, delays or abandonment of the project will not impair the Company's ability to provide gas to its customers.

Future capital requirements do not reflect the potential costs associated with the President's proposed Clean Air Act legislation. The provisions for stack emission limitations, including the timing and level of reductions, could substantially increase capital requirements through 1994, primarily at the Company's Huntley and Dunkirk coal stations. The Company is presently unable to assess the potential costs that may be associated with the passage of the proposed Clean Air Act.

Provisions have been made within the capital requirements forecast to address the investigation and remediation of both Company owned and Company associated hazardous waste sites. Such amounts, which approximate $55 million through 1994 and include the Company's share of remediation costs for sites with which it is associated, are estimates based upon certain site specific studies and, in most cases, preliminary assessments of the extent of contamination. The Company is awaiting approval by the appropriate regulatory agencies of plans submitted to remediate certain sites. Actual Company expenditures for these sites is dependent upon the total cost of investigation and remediation, as well as the determination of the Company's share of responsibility for such costs. The Company believes that costs incurred in the investigation and restoration process are recoverable in the ratesetting process. (See Note 12 of Notes to Consolidated Financial Statements under "Environmental Issues").

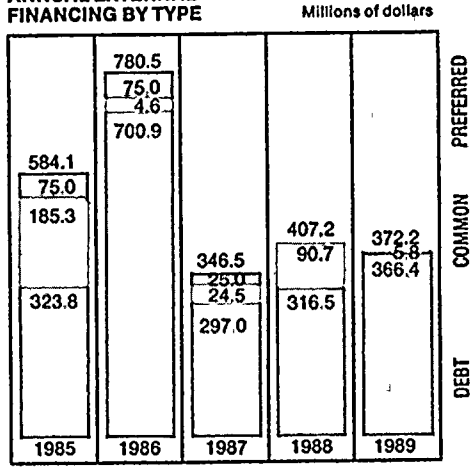
The Nuclear Regulatory Commission (NRC) issued regulations in 1988 requiring owners of nuclear power plants to place costs associated with decommissioning activities for contaminated portions of nuclear facilities into an external trust at a substantially accelerated rate from what has heretofore been 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. Based upon studies applying the NRC guidelines, the Company has estimated that the minimum requirements for Unit 1 and its share of Unit 2, respectively, will be $305 million and $396 million in future dollars. These amounts exceed the current PSC ordered cost recovery allowance for total decommissioning costs associated with the Units. As a result, the NRC regulations requiring an external trust and establishing a minimum funding level, which have not been considered in the ratesetting environment, could require the Company to increase its future capital requirements. In an application filed on August 4, 1989 to increase the Company's electric and gas base rates, the requested allowances for recovery of decommissioning costs for Units 1 and 2 were based upon the Company's revised decommissioning cost estimates and compliance with the NRC guidelines. The Company can provide no assurance as to the allowances which will ultimately be approved by the PSC. The Company has until July 1990 to file a decommissioning report for each Unit with the NRC. On March 1, 1989 the PSC issued an order requesting comments from utilities in connection with a generic proceeding to examine the funding and taxation aspects of accumulating nuclear decommissioning funds in an external trust in response to the NRC regulations. The Company has responded to the order and is awaiting final resolution of this matter by the PSC.

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 Statements of Cash Flows on page 25.

During 1989, the Company raised approximately $372.2 million through external sources, consisting of $400 million of debt, $5.8 million of common stock from the issuance of 466,558 new shares through the Dividend Reinvestment and Employee Stock Plans and a net decrease of $33.6 million of short-term debt and intermediate term bank revolving credit obligations. The Company also completed $6.3 million of capital lease financing and raised $71 million internally through the sale of an additional portion of its accounts receivable. These amounts include external financing done directly by the Company's subsidiaries, which amounted to $23.9 million in 1989 through bank revolving credit borrowings.

ANNUAL EXTERNAL FINANCING BY TYPE

Millions of dollars



The Company expects external financing of approximately $208 million in 1990. This level of financing anticipates a return to service of Unit 1 in the second quarter of 1990, omission of the common stock dividend through 1990 and is impacted by certain provisions of the 1989 Agreement (See Note 11 of Notes to Consolidated Financial Statements). To minimize the dilutive effect on earnings per share of the issuance of new common stock, the Company suspended sales of new common stock under the Dividend Reinvestment and Employee Stock Plans effective during

the first quarter of 1989 and has since purchased these requirements on the open market. The anticipated amount of external financing in 1990 reflects this decision. Although external financing plans for 1991 to 1994 have not been finalized, the aggregate level of financing during this four year period will reflect, 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, capital expenditures relating to load reliability projects and gas pipeline expansion (including the Trans York pipeline to bring gas supply from Canada, if approved), the effects of rate regulation and various regulatory initiatives as well as 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, 1989, under the applicable earnings test set forth in the indenture, the Company would be permitted to issue up to $850 million of First Mortgage Bonds assuming a 10¼% 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 $321 million of First Mortgage Bonds. In addition, the Company has the ability to issue approximately $1,021 million of First Mortgage Bonds at December 31, 1989 on the basis of retired bonds without regard to the earnings or Additional Property tests. $100 million of Preference Stock is currently authorized for sale and is expected to be issued in 1990. The Company does not expect to be able to issue additional Preferred Stock until 1993, 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. In January 1990, the Company sold an additional $29 million of accounts receivable. (See Note 12 of Notes to Consolidated Financial Statements).

The Company's ratings at December 31, 1989 were:

	Secured Debt	Unsecured Debt	Preferred Stock
Standard & Poors Corporation	BBB	BBB–	BBB–
Moody's Investors Service	Baa2	Baa3	ba2
Duff & Phelps	BBB	BBB–	BB
Fitch Investors Service	BBB–	BB+	BB

Increased levels of debt financing as necessitated by the factors discussed above, could result in a further reduction in the Company's credit rating. Further 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 downgraded to or remained below investment grade, could be expected to reduce the Company's financing flexibility and adversely affect its capital structure and financial position. Further, the Company could be precluded from issuing commercial paper, which would necessitate the use of longer-term financing and thus putting further pressure on credit ratings. Moody's lowered the Company's commercial paper rating to P3 in October, 1989. A key objective of the 1989 Agreement as discussed above, was to stabilize the Company's financial condition and attempt to maintain its senior securities ratings at investment grade. However, no assurance can be given even if the Company can achieve the targets established in the 1989 Agreement that its current senior securities' ratings will be maintained or, conversely, that failure to achieve such targets will result in a downgrade.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a continuing basis. Bank credit arrangements which, at December 31, 1989, totaled $515 million, (including $180 million in commitment under Revolving Credit Agreements, $75 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement of Oswego Facilities Trust, $54 million in one-year commitments under Credit Agreements, $106 million in lines of credit and a $100 million Bankers Acceptance Facility Agreement) are used by the Company to enhance flexibility as to the type and timing of its long-term security sales. Such credit arrangements were increased in 1989 from $335 million at December 31, 1988 to provide the Company more borrowing capability if needed.

The unsecured debt limitation imposed by the Company's charter is 10% of consolidated capitalization plus $50 million, which, as of January 1, 1990, equates to approximately $593 million and against which the Company had outstanding unsecured debt of approximately $388 million.

Consolidated Balance Sheets

At December 31,	1989	1988
	In thousands of dollars	
ASSETS		
Utility plant, at original cost *(Note 1)*:		
Electric plant	$6,726,656	$6,497,398
Nuclear fuel *(Note 3)*	410,207	404,686
Gas plant	650,175	611,671
Common plant	149,554	138,226
Construction work in progress	387,520	315,644
Total utility plant	8,324,112	7,967,625
Less accumulated depreciation and amortization	2,283,307	2,090,170
Net utility plant	6,040,805	5,877,455
Other property and investments	215,836	155,257
Current assets:		
Cash, including time deposits of $26,475 and $11,335, respectively	47,912	19,027
Accounts receivable (less allowance for doubtful accounts of $3,600) *(Note 12)*	205,260	228,914
Unbilled electric revenues *(Note 1)*	131,100	126,000
Materials and supplies, at average cost:		
Coal and oil for production of electricity	69,071	47,382
Other	113,550	76,950
Prepayments:		
Taxes	44,814	39,914
Pension expense *(Note 8)*	89,150	6,398
Other	25,121	20,244
	725,978	564,829
Deferred debits:		
Unamortized debt expense	121,515	128,520
Deferred recoverable energy costs	93,846	32,239
Deferred finance charges *(Note 1)*	239,880	239,880
Deferred operating expenses *(Note 11)*	13,980	—
Other	123,253	77,861
	592,474	478,500
	$7,575,093	$7,076,041
CAPITALIZATION AND LIABILITIES		
Capitalization *(Note 7)*:		
Common stockholders' equity:		
Common stock, issued 136,099,654 and 135,633,096 shares, respectively	$ 136,100	$ 135,633
Capital stock premium and expense	1,649,285	1,640,593
Retained earnings	129,146	105,168
	1,914,531	1,881,394
Non-redeemable preferred stock	290,000	290,000
Redeemable preferred stock	267,530	295,510
Long-term debt	3,249,328	2,995,748
Total capitalization	5,721,389	5,462,652
Current liabilities:		
Short-term debt *(Note 4)*	35,671	108,000
Long-term debt due within one year	196,508	110,571
Sinking fund requirements on redeemable preferred stock *(Note 7)*	17,980	17,980
Accounts payable	291,658	219,798
Payable on outstanding bank checks	47,810	82,279
Customers' deposits	10,088	9,985
Accrued taxes	10,379	16,132
Accrued interest	81,533	71,842
Accrued vacation pay	30,379	29,904
Other	40,675	39,640
	762,681	706,131
Deferred credits:		
Mandated refunds to customers	—	5,613
Accumulated deferred Federal income taxes	656,235	562,811
Deferred finance charges *(Note 1)*	239,880	239,880
Unbilled electric revenues *(Note 1)*	45,899	63,534
Deferred pension settlement gain *(Note 8)*	79,304	—
Other	69,705	35,420
	1,091,023	907,258
Commitments and contingencies *(Notes 3, 10 and 12)*	—	—
	$7,575,093	$7,076,041

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	1989	1988	1987
		In thousands of dollars	
Operating revenues:			
Electric	$2,418,662	$2,343,732	$2,170,191
Gas	487,381	456,721	453,239
	2,906,043	2,800,453	2,623,430
Operating expenses:			
Operation:			
Fuel for electric generation	415,362	360,373	339,382
Electricity purchased	355,706	343,511	326,152
Gas purchased	288,734	265,033	268,099
Other operation expenses	558,073	467,873	383,874
Maintenance	206,214	200,969	158,939
Depreciation and amortization *(Note 2)*	210,873	182,209	157,631
Federal and foreign income taxes *(Note 9)*	105,103	134,451	195,472
Other taxes	354,019	329,869	308,483
Amortization of investment in generating station project *(Note 2)*	—	39,813	—
	2,494,084	2,324,101	2,138,032
Operating income	411,959	476,352	485,398
Other income and deductions:			
Allowance for other funds used during construction *(Note 1)*	10,085	5,149	20,563
Federal income taxes	14,770	13,587	17,622
Current year effect of adoption of SFAS No. 90 *(Note 10)*:			
Disallowed plant costs	—	—	(268,400)
Related income taxes	—	—	50,400
Other items (net)	11,734	(19,945)	10,947
	36,589	(1,209)	(168,868)
Income before interest charges	448,548	475,143	316,530
Interest charges:			
Interest on long-term debt	296,232	264,866	264,472
Other interest	10,824	7,336	4,587
Allowance for borrowed funds used during construction	(9,291)	(5,873)	(10,315)
	297,765	266,329	258,744
Income before cumulative effect of accounting change	150,783	208,814	57,786
Cumulative effect on prior years of adoption of SFAS No. 90 *(Note 10)*	—	—	(615,000)
Net income (loss)	150,783	208,814	(557,214)
Dividends on preferred stock	45,182	49,157	52,017
Balance available for common stock	105,601	159,657	(609,231)
Dividends on common stock	81,623	158,228	208,881
	23,978	1,429	(818,112)
Retained earnings at beginning of year	105,168	103,739	921,851
Retained earnings at end of year	$ 129,146	$ 105,168	$ 103,739
Average number of shares of common stock outstanding *(In thousands)*	136,052	131,853	127,435
Per average share of common stock:			
Balance available for common stock before cumulative effect of accounting change	$ .78	$ 1.21	$ .05
Cumulative effect on prior years of adoption of SFAS No. 90 *(Note 10)*	—	—	(4.83)
Balance available for common stock	$ .78	$ 1.21	$ (4.78)
Dividends paid	$ .60	$ 1.20	$ 1.64

( ) Denotes deduction

Consolidated Statements of Cash Flows
Increase (Decrease) in Cash

For the year ended December 31,	1989	1988	1987
	In thousands of dollars		
Cash flows from operating activities:			
Net income (loss)	$150,783	$208,814	$(557,214)
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	210,873	222,022	157,631
Amortization of nuclear fuel	20,767	16,362	28,748
Loss on investment in NM Uranium, Inc.	14,500	7,500	13,000
Provision for deferred Federal income taxes	85,733	88,761	102,340
Allowance for other funds used during construction	(10,085)	(5,149)	(20,563)
Deferred recoverable energy costs	(61,607)	(23,803)	1,499
Gain on sale of investments	(7,660)	(1,477)	(13,000)
Unbilled electric revenues	(22,735)	(62,466)	—
Decrease in mandated refunds to customers	(5,613)	(30,554)	(27,062)
Deferred operating expenses	(13,980)	—	—
(Increase) decrease in net accounts receivable	23,654	76,114	(15,678)
(Increase) in materials and supplies	(34,973)	(3,000)	(3,452)
Increase in accounts payable and accrued expenses	63,315	46,727	38,667
Increase (decrease) in accrued interest and taxes	3,938	(2,198)	11,181
Changes in other assets and liabilities	2,349	(28,366)	(27,807)
Net cash provided by operating activities	419,259	509,287	571,690
Cash flows from investing activities:			
Construction additions	(387,178)	(349,823)	(409,068)
Nuclear fuel	(18,416)	(3,759)	(28,765)
Less: Allowance for other funds used during construction	10,085	5,149	20,563
Acquisition of utility plant	(395,509)	(348,433)	(417,270)
(Increase) decrease in materials and supplies	(23,316)	(2,133)	772
Increase (decrease) in accounts payable and accrued expenses	15,829	12,877	(6,334)
Payments under Cotenant Agreement	—	(171,100)	—
Increase in other investments	(52,162)	(39,723)	(22,823)
Other	(6,426)	9,197	12,333
Net cash used in investing activities	(461,584)	(539,315)	(433,322)
Cash flows from financing activities:			
Proceeds from sale of common stock	5,841	90,683	24,459
Proceeds from sale of preferred stock	—	—	25,000
Sale of mortgage bonds	300,000	200,000	100,000
Issuance of other long-term debt	100,000	69,800	270,060
Redemption of preferred stock	(27,980)	(56,980)	(62,380)
Reductions of long-term debt	(98,652)	(137,193)	(273,005)
Net change in short-term debt and revolving credit agreements	(33,629)	46,736	(72,987)
Dividends paid	(126,805)	(207,385)	(260,898)
Change in dividends payable	(41,175)	30,217	(7,693)
Other	(6,390)	(16,614)	(27,112)
Net cash provided by (used in) financing activities	71,210	19,264	(284,556)
Net increase (decrease) in cash	28,885	(10,764)	(146,188)
Cash at beginning of year	19,027	29,791	175,979
Cash at end of year	$ 47,912	$ 19,027	$ 29,791
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$314,328	$299,351	$ 284,348
Income taxes	3,577	42,348	44,479
Supplemental schedule of noncash investing and financing activities:			
Capital lease obligations incurred	$ 6,293	$ 12,560	$ 19,276

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.

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.

Reclassifications: Certain amounts have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1989 presentation.

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). Replacement of minor items of utility plant and 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, 1989 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 Statements of Income.

Effective April 1985, pursuant to 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 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, 1989 and 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 (Unit 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 "Nuclear Plant Decommissioning").

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 $22.7 million and $62.5 million of such accrued electric revenues are included in the results of operations for the years ended December 31, 1989 and 1988, respectively, as specified within the Stipulation Agreement and the remainder is included in Deferred Credits. Remaining unrecognized amounts may be used to reduce future revenue requirements. Pursuant to the Stipulation Agreement, a total of $102 million of unbilled revenues will have been recognized through June 30, 1990.

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 "PSC Investigation of the Unit 1 Outage").

Federal Income Taxes: In accordance with PSC requirements, the tax effect of book and tax timing differences is flowed through except as required by the Internal Revenue Code or 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 when incurred or allocated for tax purposes and capitalized and depreciated 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 Financial Accounting Standards Board (FASB) has issued Statements of Financial Accounting Standards No. 96 and No. 100 (SFAS No. 96 and No. 100) "Accounting for Income Taxes" and has recently issued a third SFAS (SFAS No. 103) which will require the adoption of SFAS 96 for fiscal years beginning after December 15, 1991. The pronouncements continue the present comprehensive inter-period tax allocation rules, but shift to the use of the liability method for accounting for deferred taxes rather than the deferred method required under Accounting Principles Board (APB) Opinion No. 11. Regulated utilities are not exempt from the provisions of SFAS No. 96, which specifically prohibit net-of-tax accounting and reporting and require (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).

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

NOTE 2. Depreciation and Amortization

The total provision for depreciation and amortization, including amounts charged to clearing accounts, was $212,067,000 for 1989, $183,385,000 for 1988 and $158,761,000 for 1987. 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 million representing a portion of carrying charges accrued on LEGS, was charged 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 2.9% in 1989, 2.7% in 1988 and 3.0% in 1987. 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 and expected to continue into the late 1990's. 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 $35.0 million and $20.5 million at December 31, 1989 and 1988, respectively, totaled $30.1 million at December 31, 1989 and $44.9 million at December 31, 1988.

In connection with the Company's rate decisions in March 1984, March 1986 and the Stipulation Agreement in 1988, 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 Unit 1 and approximately 107,000 lbs. utilized for a portion of the initial core at Unit 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 before valuation reserve 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 Unit 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 1992.

Based upon DOE's recently issued uranium price report which reflects a continued decline in average delivery prices from previous forecasts and the anticipated further decline in average delivery prices, the Company now expects that, based

upon costs allowed in rates to date and the estimated value of remaining transfers, a minimum of $35 million of its investment in NMU may not be recoverable in rates. Accordingly, the Company has reduced the carrying value of such investment by $14.5 million in 1989, $7.5 million in 1988 and $13 million in 1987. The Company can provide no assurance that all of its remaining investment in NMU will ultimately be recovered; however, if the remaining 955,000 pounds of uranium were transferred at the January 1, 1990 spot market price of $9.00/pound (contrasted with the DOE price of $25.65/pound allowed for the 1988 transfer), an additional reserve of approximately $16 million would be necessary.

NOTE 4. Bank Credit Arrangements

At December 31, 1989, the Company had $515 million of bank credit arrangements with 30 banks. These credit arrangements consisted of $180 million in commitments under Revolving Credit Agreements (including Revolving Credit Agreement for HYDRA-CO), $75 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement for Oswego Facilities Trust, $54 million in one-year commitments under Credit Agreements, $106 million in lines of credit and $100 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreements extend into 1990 and 1991, and the interest rate applicable to borrowing is based on certain rate options available under the Agreements. 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 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.

Amounts outstanding under Interest Rate Exchange Agreements and Revolving Credit Agreements totaled $75 million at December 31, 1989 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:	**1989**	**1988**
Short-term debt:		
Commercial paper	$ —	$ 81,000
Notes payable	28,926	—
Bankers acceptances	6,745	27,000
	$ 35,671	$108,000
Weighted average interest rate *(a)*	11.40%	9.28%
For year ended December 31:		
Daily average outstanding	$ 80,583	$ 46,254
Monthly weighted average interest rate *(a)*	9.62%	7.58%
Maximum amount outstanding	$249,300	$173,100

(a) Excluding fees.

NOTE 5. 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 of such common property have been allocated to the segments in accordance with practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain 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		
	1989	**1988**	**1987**
Operating revenues:			
Electric	$2,418,662	$2,343,732	$2,170,191
Gas	487,381	456,721	453,239
Total	$2,906,043	$2,800,453	$2,623,430
Operating income before taxes:			
Electric	$ 466,145	$ 564,275	$ 637,120
Gas	50,917	46,528	43,750
Total	$ 517,062	$ 610,803	$ 680,870
Pretax operating income, including AFC:			
Electric	$ 484,706	$ 574,426	$ 667,610
Gas	51,732	47,399	44,138
Total	536,438	621,825	711,748
Income taxes	105,103	134,451	195,472
Other income and deductions	26,504	(6,358)	(189,431)
Interest charges	307,056	272,202	269,059
Cumulative effect of accounting change	—	—	(615,000)
Net income *(loss)*	$ 150,783	$ 208,814	$ (557,214)
Depreciation and amortization:			
Electric	$ 195,372	$ 167,566	$ 143,508
Gas	15,501	14,643	14,123
Total	$ 210,873	$ 182,209	$ 157,631
Construction expenditures (including nuclear fuel):			
Electric	$ 356,785	$ 316,798	$ 417,887
Gas	55,102	49,344	39,222
Total	$ 411,887	$ 366,142	$ 457,109
Identifiable assets:			
Electric	$6,229,107	$5,910,897	$5,626,117
Gas	581,900	539,309	491,315
Total	6,811,007	6,450,206	6,117,432
Corporate assets	764,086	625,835	676,666
Total assets	$7,575,093	$7,076,041	$6,794,098

NOTE 6. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1989. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income.

		In thousands of dollars		
	Percentage ownership	Utility plant	Accumulated depreciation	Construction work in progress
Roseton Steam Station Units No. 1 and 2*(a)*	25	$ 83,993	$33,749	$ 128
Oswego Steam Station Unit No. 6*(b)*	76	$ 264,342	$71,904	$3,056
Nine Mile Point Nuclear Station Unit No. 2*(c)*	41	$1,478,255	$62,056	$7,623

(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%). Central Hudson Gas and Electric Corporation has agreed to acquire the Company's 25% interest in the plant in ten equal installments of 2.5% (30 mw) starting on December 31, 1994 and on each December 31 thereafter. The agreement is subject to PSC approval.

(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 7. Capitalization

CAPITAL STOCK

The Company is authorized to issue 150,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 4,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1987, 1988 and 1989:

	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, 1987:	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
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
Issued to stock purchase plans in 1989	466,558	467							5,375
Redemptions			(58,000)	—	(5,800)	(887,199)	—	(22,180)	137
Foreign currency translation adjustment									3,180
Balance December 31, 1989:	136,099,654	$136,100	2,586,000	$210,000	$48,600*(a)*	12,676,403	$80,000	$236,910*(a)*	$1,649,285

**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 1989	1988	1987	Redemption price per share (Before adding accumulated dividends) December 31, 1989	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 1989	1988	1987	Redemption price per share (Before adding accumulated dividends) December 31, 1989	Eventual minimum
Preferred $100 par value:					
7.45% Series; 366,000, 384,000 and 402,000 shares	$ 36,600	$ 38,400	$ 40,200	$103.61	$100.00
10.13% Series; none and 225,000 shares	—	—	22,500	—	—
10.60% Series; 120,000, 160,000 and 200,000 shares	12,000	16,000	20,000	107.95	102.65
Preferred $25 par value:					
8.375% Series; 900,000, 1,000,000 and 1,100,000 shares	22,500	25,000	27,500	25.88	25.00
8.70% Series; 1,000,000 shares	25,000	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; 540,000, 606,000 and 672,000 shares	13,500	15,150	16,800	25.78	25.00
10.13% Series; none and 900,000 shares	—	—	22,500	—	—
10.75% Series; 960,000 and 1,600,000 shares	24,000	40,000	40,000	25.90	25.00
12.25% Series; 570,820, 613,880 and 656,940 shares	14,270	15,347	16,423	(b)	25.00
12.50% Series; 505,583, 543,722 and 581,861 shares	12,640	13,593	14,547	(b)	25.00
Adjustable Rate Series B; 2,000,000 shares	50,000	50,000	50,000	25.75	25.00
	285,510	313,490	370,470		
Less sinking fund redemption requirements	17,980	17,980	14,980		
	$267,530	$295,510	$355,490		

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

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	In thousands of dollars 1990	1991	1992	1993	1994
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	5,000
8.75% Series	600,000	12/31/92	—	—	15,000	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(a)	—	—
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	1,250
			$17,980	$17,980	$32,980	$31,230	$31,230

(a) Redemption completed in 1992.

LONG-TERM DEBT

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

At December 31,	In thousands of dollars 1989	1988
First mortgage bonds:		
12% Series due March 1, 1989	$ —	$ 20,000
* 9⅛% Series due October 1, 1989	—	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	200,000
6½% Series due August 1, 1998	60,000	60,000
10¼% Series due February 1, 1999	100,000	—
10⅜% Series due April 1, 1999	100,000	—
9⅛% Series due December 1, 1999	75,000	75,000
12.95% Series due October 1, 2000	42,669	48,002
7⅜% Series due February 1, 2001	65,000	65,000
9¼% Series due October 1, 2001	100,000	—
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	41,177	44,118
9.95% Series due September 1, 2004	75,000	80,000
10.20% Series due March 1, 2005	29,000	30,478
8.35% Series due August 1, 2007	66,640	66,640
8⅝% Series due December 1, 2007	36,000	38,000
*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	2,386,191	2,135,943
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	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 1989-2004	251,100	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	50,000	75,000
Revolving credit agreement, Oswego Facilities Trust	63,700	—
Other	135,512	135,909
Unamortized premium (discount)	(1,027)	(893)
TOTAL LONG-TERM DEBT	3,445,836	3,106,319
Less long-term debt due within one year	196,508	110,571
	$3,249,328	$2,995,748

* 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 notes 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 5.88% for 1989 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.

During 1988 and 1989, the Company issued $300 million of unsecured medium term notes at various rates. The aggregate maturities of these notes for the five years subsequent to December 31, 1989, are $29.0 million, $77.9 million, $56.5 million, $32.2 million and $10.5 million, respectively.

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 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. In August 1989, the Trust resumed issuing commercial paper and the interest rate exchange agreement was transferred back to the Trust.

The arrangements with the Trust provide financing for the construction of a new energy management system. The Trust has a $75,000,000 Direct Pay Letter of Credit Facility and Revolving Credit Agreement, $25,000,000 of which is subject to an Interest Rate Exchange Agreement and is used to support its commercial paper obligations. All such obligations are secured by certain assets held by the Trust. The Company is required to purchase, or otherwise arrange for, the disposition of the Trust assets upon the termination of the Trust. The Letter of Credit Facility and Revolving Credit Agreement of the Trust require payment of fees which are based upon the amount of commercial paper outstanding.

Other long-term debt in 1989 consists of obligations under capital leases of $59,296,000 (See Note 12) and a liability to the U.S. Department of Energy for nuclear fuel disposal of $76,216,000. (See Note 10. "Nuclear Fuel Disposal Cost").

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	In thousands of dollars 1990	1991	1992	1993	1994
First Mortgage Bonds:							
10.20% Series due March 1, 2005	$1,500	3/1/78	$ 1,500	$ 1,500	$ 1,500	$ 1,500	$ 1,500
8.35% Series due August 1, 2007	750	8/1/82	*(a)*	*(a)*	*(a)*	640*(a)*	750
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	700
			$17,274	$17,274	$17,374	$18,014	$18,224

(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 the certification of additional property, the waiver of the issuance of additional bonds or the retirement of outstanding bonds. The 1989 requirements for these series were satisfied by the certification of additional property. The Company anticipates that the 1990 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 at December 31, 1989, are $6,050,000.

NOTE 8. Pension and Other Retirement Plans

The Company and certain of its subsidiaries have non-contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on the employee's years of service and compensation level. The pension cost was $18.8 million for 1989, $26.0 million for 1988 and $30.2 million for 1987 (of which $5.0 million for 1989, $7.8 million for 1988 and $11.4 million for 1987 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 1989 and 1988 included the following components:

	In thousands of dollars	
At December 31,	1989	1988
Service cost—benefits earned during the period	$ 21,600	$ 22,900
Interest cost on projected benefit obligation	42,200	56,300
Return on Plan assets	(47,800)	(56,000)
Amortization of net obligation	2,800	2,800
Net pension cost	$ 18,800	$ 26,000

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

	In thousands of dollars	
at December 31,	1989	1988
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$250,266	$516,014
Non-vested benefits	43,338	34,401
Accumulated benefit obligations	293,604	550,415
Additional amounts related to projected pay increases	163,852	194,405
Projected benefits obligation for service rendered to date	457,456	744,820
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	600,673	811,094
Plan assets in excess of projected benefit obligations	143,217	66,274
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	43,561	46,354
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	(27,837)	(119,040)
Gain from settlement of pension obligations	(82,752)	—
Prior service cost not yet recognized in net periodic pension cost	340	210
Prepaid (accrued) pension costs included in other current assets and liabilities	$ 76,529	$ (6,202)

In 1989 and 1988, the discount rate and rate of increase in future compensation levels used in determining the actuarial present value of the projected benefit obligations were 8.00% and 4.50% (plus merit increases) and 8.25% and 4.50% (plus merit increases), respectively. The expected long-term rate of return on plan assets was 9.00% in 1989 and 8.75% in 1988.

Included as an item of income is a portion of a pension settlement gain realized from the purchase of a group annuity relating to obligations to existing retirees. The total gain from the pension settlement of approximately $83 million, which would generally be recognized immediately in earnings, was initially deferred pending future regulatory consideration. Pursuant to the 1989 Agreement, the Company began amortizing the pension settlement gain over an eighteen year period beginning in April 1989.

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for active and retired employees and dependents. Under current policies, substantially all of the Company's employees may be eligible for continuation of some of these benefits upon normal or early retirement. These benefits are provided through insurance companies whose charges and premiums are based on the claims paid during the year. The cost of providing these benefits to retired employees amounted to approximately $11.8 million for 1989, $12.6 million for 1988, and $8.8 million for 1987.

In 1989, the FASB issued an Exposure Draft entitled "Employers' Accounting for Postretirement Benefits Other Than Pensions". This proposed statement would require, among other things, accrual accounting by employers for post-retirement benefits other than pensions reflecting currently earned benefits and disclosure of the total vested post retirement liability. The Company currently accounts for such costs on a cash basis for both active and retired employees. This proposed change would become effective in 1992. The effect on the Company's financial condition of the adoption of this proposed statement is dependent upon the regulatory treatment afforded accrued post retirement costs.

NOTE 9. Federal and Foreign Income Taxes

Income Tax Reform: The Tax Reform Act of 1986 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 1989 and 1988 and the blended statutory rate of approximately 40% for 1987.

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1989	1988	1987
United States	$234,527	$322,814	$180,213
Foreign	24,704	16,485	28,594
Consolidating eliminations	(18,115)	(9,621)	(23,571)
Income before income taxes and the cumulative effect of the accounting change in 1987	$241,116	$329,678	$185,236

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

Summary Analysis:	*In thousands of dollars* 1989	1988	1987
Components of Federal and foreign income taxes:			
Current tax expense: Federal	$ 24,627	$ 60,173	$ 39,574
Foreign	4,728	998	4,606
	29,355	61,171	44,180
Deferred tax expense: Federal	70,851	66,996	146,886
Foreign	4,897	6,284	4,406
	75,748	73,280	151,292
Income taxes included in Operating Expenses	105,103	134,451	195,472
Current Federal tax credits associated with disallowed plant depreciation	(24,755)	(29,068)	(19,070)
Deferred Federal income tax expense (credits) included in Other Income and Deductions	9,985	15,481	(48,952)
Total	$ 90,333	$120,864	$127,450
Components of deferred Federal income taxes *(Note 1):*			
Depreciation	$ 90,920	$116,397	$101,206
Investment tax credit	(9,116)	(392)	49,303
Alternative minimum tax	(17,363)	(33,786)	—
Benefit associated with disallowed plant costs	—	—	(50,400)
Construction overheads	1,386	(2,826)	14,492
Recoverable energy and purchased gas costs	25,987	8,664	(3,858)
Unbilled revenues	(6,686)	4,912	(15,181)
Reacquisition of bonds	(1,331)	(2,463)	3,299
Deferred operating expenses	4,698	—	—
Other	(2,762)	(1,745)	3,479
Deferred Federal income taxes (net)	$ 85,733	$ 88,761	$102,340
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	$ 81,979	$112,091	$ 74,002
Reduction (increase) attributable to flow-through of certain tax adjustments:			
Depreciation	(30,645)	(18,959)	(24,160)
Allowance for funds used during construction	7,130	3,747	12,336
Taxes, pensions and employee benefits capitalized for accounting purposes	(273)	3,929	(798)
Real estate taxes on an assessment date basis	1,934	2,537	859
Deferred investment tax credit amortization	9,381	10,092	7,328
Tax adjustments associated with disallowed plant costs	—	—	(56,826)
Other	4,119	(10,119)	7,813
	(8,354)	(8,773)	(53,448)
Federal and foreign income taxes	$ 90,333	$120,864	$127,450

NOTE 10. Nuclear Operations

The Company is the owner and operator of Unit 1 and the operator and a 41% co-owner of Unit 2 (See Note 6). Contingencies involving the Company's ownership of these facilities are discussed below.

NRC Assessment of Nine Mile Point Station Performance: In December 1988, Nuclear Regulatory Commission (NRC) senior managers conducted their semi-annual review of the performance of nuclear power plants licensed by the NRC. As a result of this review, the Company was advised that the Nine Mile Point Station (Units 1 and 2) was being categorized as requiring close monitoring by the NRC, a conclusion that was subsequently supported at a meeting of the NRC Commissioners on December 21, 1988. The conclusion was based on the NRC's 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. Further, the Staff of the NRC (the NRC Staff) observed that increased licensee and NRC attention is needed to ensure that performance improvement at the Nine Mile Point Station is achieved. The Nine Mile Point Station continues to be categorized as requiring close monitoring by the NRC.

Unit 1 Outage: 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 required in-service inspections. Inspections are continuing.

During July 1988, the Company received a letter from the NRC Staff stating that Unit 1 was identified as having weaknesses that warrant increased NRC attention and require close monitoring. Citing a March 1988 civil penalty relating to in-service inspections, an April 1988 Systematic Appraisal of Licensee Performance (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 in July 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 a final version of this Restart Action Plan to the NRC Region I Administrator on July 11, 1989. NRC approval of the Restart Action Plan was received on September 29, 1989.

During September 1989, the Company notified the NRC of its readiness to restart Unit 1 upon completion of certain activities in the Restart Action Plan. Beginning on October 4, 1989, an NRC inspection team evaluated the Company's readiness to restart Unit 1. The results of the inspection, which were released in a report to the Company on November 8, 1989, were that overall there were no fundamental flaws in the implementation of the Company's Restart Action Plan. The report did note, however, two areas where implementation was weak, but improving: problem solving and standards of performance/self-assessment. The Company believes that, subject to improving on the weaknesses noted in the report, restart of Unit 1 will not be affected by the results of this inspection. The Company has responded to the report, agreeing that there were no fundamental flaws in the Restart Action Plan, and that specific noted weaknesses will be addressed.

In late December 1989, the Company began preparations to load fuel into Unit 1's reactor. Fuel load was completed on January 18, 1990, representing the achievement of a significant milestone in the Company's efforts to return Unit 1 to service. However, additional work is required before the Company will be prepared to restart Unit 1.

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 an assessment by the Company of the tasks to be completed prior to restart of Unit 1, including completion of physical work necessary to permit restart and NRC concurrence as to the Company's readiness to restart, the Company anticipates that Unit 1 will not be ready to restart prior to the second quarter of 1990. The Company anticipates a six to eight week power ascension program upon restart, however the Company cannot predict whether delays will occur due to potential emergent work arising as a result of discoveries during power ascension. The Company can provide no assurance that the current scope of effort to be completed prior to restart will not be expanded by future events of which the Company is not currently aware. Also, the Company cannot predict with assurance the time period or results of the NRC review which is required to permit restart of Unit 1.

PSC Investigation of the Unit 1 Outage: In May 1988, the Attorney General of the State of New York filed a petition with the PSC requesting that the PSC, 1) order the Company to 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 in September 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 Staff of the PSC (PSC Staff), the Attorney General, the New York State 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 provided that the Company, commencing with the fuel cost month of January 1989 until the earlier of restart of Unit 1 or June 30, 1989, would temporarily suspend collection from ratepayers of $225 thousand per day in replacement power costs through the fuel adjustment clause mechanism. This reduced the Company's cash flow during the term of the agreement by approximately $40.7 million.

The Interim Relief Agreement obviated the need for the Company to litigate at that time the question of the appropriateness of interim rate relief and thus permited continued concentration of the Company's resources on the effort to restart Unit 1. The Interim Relief Agreement did not resolve any issues of responsibility which may arise during the conduct of the prudence investigation and was not an admission of imprudence by the Company.

The Company deferred, for regulatory purposes only, replacement power cost revenues associated with the Interim Relief Agreement 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 precluded the accrual of these revenues for financial reporting purposes, which reduced earnings per share during 1989 by approximately $.20.

Unit 1 did not return to service by June 30, 1989 and the Interim Relief Agreement expired by its terms, although the parties to the Interim Relief Agreement were free to seek an extension of interim relief. Pursuant to the 1989 Agreement, (See Note 11. Rates and Regulatory Matters—1989 Agreement) the parties thereto, and the PSC, agreed to refrain from filing any request for cessation of the flow-through to customers of Unit 1 replacement power costs so long as the 1989 Agreement is in effect; however, such costs collected will remain subject to the Unit 1 outage prudence investigation.

With the expiration of the Interim Relief Agreement, the Company has begun collecting from customers the replacement power costs incurred after June 30, 1989. Based upon management's current assessment, the Company has deferred for recovery through the fuel adjustment clause mechanism the replacement power costs associated with the fuel cost months of July through December 1989. The Company's ability to record future replacement power costs recovered through the fuel adjustment clause mechanism as revenues for financial reporting purposes is dependent upon an ongoing evaluation by management of the then current facts and circumstances surrounding the investigation of the Unit 1 outage. Inability to record these revenues could impact the Company's attainment of the 1.60 times interest coverage floor and the target coverages established in the 1989 Agreement. (See Note 11. Rates and Regulatory Matters—1989 Agreement).

In addition to amounts absorbed pursuant to the Interim Relief Agreement, the Company has also absorbed its share of the replacement power costs as provided for in the fuel adjustment clause mechanism, as well as the incremental operating expenses occasioned by the outage which were not provided for in rates. From the beginning of the outage, through December 31, 1989, replacement power costs have averaged approximately $332,000 per day, as determined using a New York Power Pool/Canadian supplier average cost per KWH.

Based upon assumptions utilized in determining the amount of replacement power costs occasioned by the Unit 1 outage, the Company has estimated that, through December 31, 1989, it has collected from ratepayers up to $154 million of increased fuel adjustment clause revenues. 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. During the period of the outage, through December 31, 1989,

the Company has estimated that it has absorbed approximately $58 million of replacement power costs, including amounts not collected pursuant to the Interim Relief Agreement, and approximately $97 million (approximately $69 million in 1989) of incremental Unit 1 operating and maintenance costs occasioned by the outage which are in excess of amounts provided for in the rate setting process. The precise amount of replacement power costs incurred for any given period is dependent upon seasonal factors, relative demand and availability of capacity, as well as assumptions utilized in estimating replacement power costs incurred as occasioned by the outage.

The Company is unable to predict the results of the PSC's prudence investigation, what sanctions may ultimately be imposed or 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. All formal actions in the Unit 1 prudence proceeding have been held in abeyance pending efforts to resolve a number of outstanding regulatory matters, pursuant to the terms of the 1989 Agreement. (See Note 11. Rates and Regulatory Matters—1989 Agreement.)

Clean-Up of Radwaste Spill at Unit 1: In August 1989, an NRC inspection team began an investigation of the circumstances surrounding a 1981 spill of radioactive waste containers in a storage facility at Unit 1. Management strongly believes that at no time has the health and safety of the public or the Company's employees been endangered by the spill.

The NRC released a report to the Company on October 3, 1989 detailing the findings of the NRC inspection team. The report indicated that while the NRC concurred with the Company's assessment that at no time has the health and safety of the public or the Company's employees been endangered, the Company may have committed two violations. The NRC has not yet determined what sanctions, if any, may be imposed on the Company, including a possible monetary fine. An enforcement conference was held on October 30, 1989 and the Company is awaiting a decision from the NRC on the matter of sanctions. The Company expects to begin clean-up of the spill in early 1990.

Pursuant to the 1989 Agreement, the Company will absorb the cost of the clean-up effort above amounts previously provided in rates. The Company does not expect that the cost of the clean-up will have a material impact on its financial condition or results of operations or that the issue of the spill will impact restart of Unit 1.

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 was extended to effect repair and retest of a main steam isolation valve, repair of generator retaining rings, replacement of a generator coupling, and repair and retest of six valves in the residual heat removal system. In February 1989, when activities required to allow the Unit to start up were virtually complete, an issue of service water valve logic was determined to prevent plant start up. This caused a forced outage from February 21, 1989 until April 5, 1989, when Unit 2 returned to service.

On March 12, 1989, the Attorney General filed a petition with the PSC to expand the scope of the Unit 1 outage prudence investigation to encompass the Unit 2 mid-cycle outage, which, as discussed above, had a duration longer than originally scheduled. In addition to asking for an investigation into the prudence of the management of the Unit 2 outage, the Attorney General requested the PSC to consider several forms of interim ratepayer relief, including deferral of the collection of some or all of the replacement power costs, removal of some or all of Unit 2 from the Company's and cotenants' rate bases, or a combination of these actions. The Company's share of replacement power costs averaged approximately $135,000 per day during the period of the outage.

Any formal action that may result from the Attorney General's petition has been held in abeyance to be dealt with pursuant to the 1989 Agreement (See Note 11—Rates and Regulatory Matters—1989 Agreement). The issue of responsibility for replacement power costs associated with operations from April 5, 1988 through January 19, 1990 has been established pursuant to an "agreement-in-principle" reached in January 1990 amongst the Company, the cotenant Companies, the PSC Staff and other intervenors. See Unit 2 Ratemaking and Cost Settlement below.

In July 1989, fourteen of forty-eight licensed operators for Unit 2 failed to pass required annual license requalification testing. Any licensed operator who fails any portion of the test is not permitted to work in the control room until that operator is recertified. Unit 2 had a sufficient number of fully qualified operators to continue operation of the plant. Subsequently, the Company successfully retested with NRC participation all but one of the failed operators in September. The Company has also implemented an action plan to correct deficiencies in the Unit 2 requalification training program that resulted in the unacceptably high examination failure rate.

Institute of Nuclear Power Operations Evaluation: In November 1989 the Institute of Nuclear Power Operations (INPO), an industry sponsored oversight group, performed an evaluation of Nine Mile Point Units 1 and 2. INPO reported deficiencies in several key areas related to monitoring devices, operator performance in the training simulator, and supervision of maintenance practices. A number of these issues had been previously noted and were being corrected or improved by the Company. The Company is preparing its responses and a Corrective Action Program with respect to the INPO findings. The Company considers that the issues raised will not prevent restart of Unit 1 or continued operation of Unit 2.

Unit 2 Ratemaking and Cost Settlement: In September 1986, the PSC approved an agreement entitled "Specifications of Terms and Conditions of Offer of Settlement" (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 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.

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 the construction costs of Unit 2.

Although the Company is unable to predict the results of the above actions, both actions would be terminated pursuant to the "agreement-in-principle" reached among the Company, the cotenant companies, the PSC Staff and other intervenors discussed more fully below.

Pursuant to the 1988 Joint Stipulation and Agreement (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. In January 1990, the Company and cotenant companies reached an "agreement-in-principle" with the PSC Staff and other intervenors with respect to remaining Unit 2 Settlement cap issues, Unit 2 operating prudence, allocation of net litigation proceeds and prospective operating and maintenance cost issues. The "agreement-in-principle", which is ultimately subject to approval by the PSC, would establish a final level of allowed Unit 2 costs as well as estop the PSC Staff from asserting that future capital additions are subject to the September 1986 Settlement. Further, all proceeds from both settled and active Unit 2 contractor litigation (as discussed in "Unit 2 Contractor Litigation" below), after deductions from such proceeds of the associated litigation costs, will be allocated equally between shareholders and ratepayers. With regard to Unit 2 operating prudence, the responsibility for and value of replacement power costs associated with operations from April 5, 1988 through January 19, 1990 has been established. The Company is unable to predict whether the "agreement-in-principle" will ultimately be approved by the PSC. See "Unit 2 Financial Accounting Recognition" below for the financial effects of the 1986 Settlement and the "agreement-in-principle."

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 which would be determined if the "agreement-in-principle" is ultimately approved by the PSC. If the "agreement-in-principle" is not approved by the PSC, the Company is unable to predict whether further regulatory actions by the PSC with respect to the Company's investment in Unit 2 will have, in the aggregate, a material effect on its financial position or results of operations.

The "agreement-in-principle" relating to remaining Unit 2 Settlement cap issues as discussed above, if ultimately approved by the PSC, would conclusively determine the amount of disallowance associated with Unit 2 construction and responsibility for replacement power costs through January 19, 1990. Based upon the loss recognized in 1987 with the Company's adoption of SFAS 90 and the terms of the "agreement-in-principle" including responsibility relating to the Unit 2 operating prudence, the Company does not believe that the recognition of the "agreement-in-principle" in its present form will have a material effect on the Company's financial condition or results of operations.

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 disputes 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 for 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.

Unit 2 Operating Agreement: The Company and cotenant companies executed an interim operating agreement in July 1989 which establishes the legal relationship between the Company (as operator and 41% owner of Unit 2) and the other cotenants. The agreement outlines the responsibilities and participation of the cotenants in the overall management of Unit 2, while the Company remains responsible for day-to-day operations.

The agreement, which has a term of eighteen months, also provides for the investigation by the Company and cotenant companies of alternative operating arrangements, including the formation of an operating company.

Nuclear Plant Decommissioning: Based on a 1989 study, the cost of decommissioning Unit 1, which is expected to begin in the year 2005, is estimated by the Company to be approximately $424 million at that time ($201 million in 1989 dollars). The Company's 41% share of the total cost to decommission Unit 2, which is expected to begin in the year 2027, is estimated by the Company to be approximately $514 million ($85 million in 1989 dollars). These amounts reflect decreases in cost from a 1986 Company study. The current annual allowances for recovery of decommissioning costs through rates as previously authorized by the PSC, are based on total estimated decommissioning costs over the life of Units 1 and 2 of $195 million and $256 million (in future dollars), respectively. Through December 31, 1989, the Company has recovered approximately $35.8 million 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 issued regulations in 1988 requiring owners of nuclear power plants to place costs associated with decommissioning activities of contaminated portions of nuclear facilities 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. Based upon studies applying the NRC guidelines, the Company has estimated that the minimum requirements for Unit 1 and its share of Unit 2, respectively, will be $305 million and $396 million in future dollars. These amounts exceed the PSC allowed basis for current cost recovery for total decommissioning costs associated with the Units. As a result, the NRC regulations requiring an external trust and establishing a minimum funding level, which have not been considered in the rate setting environment, could require the Company to increase its future capital requirements. In an application filed on August 4, 1989 to increase the Company's electric and gas base rates, the requested allowances for recovery of decommissioning costs for Units 1 and 2 were based upon the Company's revised decommissioning cost estimates and compliance with the NRC guidelines. The Company can provide no assurance as to the allowances which will ultimately be approved by the PSC. The Company has until July 1990 to file a decommissioning report for each Unit with the NRC which will include the proposed funding plan. On March 1, 1989, the PSC issued an order requesting comments from utilities in connection with a generic proceeding to examine the funding and taxation aspects of accumulating nuclear decommissioning funds in an external trust in response to the NRC regulations. The Company has responded to the order and is awaiting final resolution of this matter by the PSC.

Nuclear Liability Insurance: Under the Price-Anderson Act as amended (the Act), the public liability limit with respect to a nuclear accident at a licensed reactor is 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.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (Act) was passed into law. The Act established a cost of $.001 per kilowatt-hour of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until 1998, the year in which the Company had initially planned to ship irradiated fuel to an approved DOE disposal facility. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until 2010. The Company has several viable alternatives under consideration that will provide additional storage facilities, as necessary. Each alternative will likely require NRC approval and may require other regulatory approvals. The Company does not believe that the possible unavailability of the DOE disposal facility in 1998 will inhibit operation of either Unit.

NOTE 11. Rates and Regulatory Matters—1989 Agreement

On August 31, 1989, the Company, the staff of the New York PSC, the New York Consumer Protection Board, the New York Attorney General and Multiple Intervenors entered into the 1989 Agreement which establishes a framework within which the Company's current and future financial condition can be addressed while also providing a process for the ultimate resolution of numerous regulatory issues currently faced by the Company. In an order issued on October 20, 1989, the PSC approved the 1989 Agreement.

The 1989 Agreement addresses the Company's current financial condition by permitting the Company to attain a minimum monthly interest coverage level (without AFC) of 1.60 times through the end of 1990. This minimum coverage level will be maintained by the deferral of expenses subject to the exclusion of extraordinary losses, if any, that may occur during the period. Through December 31, 1989, the Company, in order to maintain the minimum coverage of 1.60 times, has deferred approximately $13.8 million of operating expenses for future recovery. In addition, during the last six months of 1990, minimum cash coverages of 1.60 times (without AFC and noncash items) is intended to be maintained, if necessary, through a surcharge to customers equivalent to net available transmission and resale revenues. The cash surcharge under this provision of the 1989 Agreement will serve to reduce expense deferrals otherwise permitted to achieve minimum coverages or target coverages (as described below) under the 1989 Agreement. The Company believes that the provisions of the 1989 Agreement, including the minimum cash coverage established, may enable it to maintain the investment grade status of its senior securities; however, no such assurance can be provided. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations" as to the ratings of the Company's securities and concerns as to achievement of the target coverage and minimum cash coverage.)

In accordance with the 1989 Agreement, the Company is undertaking a comprehensive self-assessment of the efficiency and effectiveness of its organization and management. On December 15, 1989, the Company submitted to the PSC a work plan describing the self-assessment approach, including a schedule for its completion. The work plan includes a mid-course milestone report to be completed on or before May 1, 1990. The Company is required to submit, by no later than November 15, 1990, a report summarizing the results of the self-assessment and provide implementation plans addressing the issues identified. With the acceptance of the work plan by the PSC on December 29, 1989, the Company is now permitted to defer up to $23 million of expenses for future recovery in an effort to achieve an interest coverage level (without AFC) of 1.75 times for the first six months of 1990. If the Company successfully completes the mid-course milestone included in the work plan by May 1, 1990, the Company will be permitted to defer additional expenses for future recovery to provide an interest coverage level of 1.85 times, also without AFC, for the

last six months of 1990. However, there is no assurance that the Company will achieve the indicated targeted coverage levels since such levels are dependent on actual results of operations and exclude extraordinary losses. Moreover, the other parties to the 1989 Agreement have the right to contest before the PSC whether the Company is reasonably carrying out the self-assessment process, and thus whether the Company has successfully achieved the mid-course milestone.

As discussed in Note 10 under "PSC Investigation of the Unit 1 Outage", the Interim Relief Agreement, by which the Company had suspended collection, effective January 1, 1989, of $225,000 per day of replacement power costs associated with the Unit 1 outage, expired by its terms on June 30, 1989. The 1989 Agreement provides that none of the parties to the 1989 Agreement, including the PSC, will request cessation of the flow-through to customers of Unit 1 replacement power costs so long as the 1989 Agreement is in effect; however, such costs collected will remain subject to the Unit 1 outage prudence investigation.

On August 31, 1989, the Board of Directors determined to omit the third quarter common stock dividend. Pursuant to the 1989 Agreement, if the Company resumes payment of common stock dividends prior to Unit 1 being fully returned to service (and achieving an average 75% capacity factor for a period of thirty consecutive days) any other party to the 1989 Agreement may withdraw therefrom and recommence litigation of the rate case discussed in the next paragraph and the other regulatory proceedings covered by the 1989 Agreement. The Company can provide no assurance that when Unit 1 has returned to service its Board of Directors will thereupon determine to resume dividend payments or as to the level at which they might be resumed (See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of other considerations affecting reinstatement of the common stock dividend).

In August 1989, the Company filed an application with the PSC requesting an increase in electric and gas rates which would, if granted, produce additional revenues of $369.6 million for the year ending June 30, 1991 (The application was subsequently revised to $344.5 million in December 1989). The PSC would have been required to decide the case by July 4, 1990; however, pursuant to the 1989 Agreement, the Company extended the period within which a decision is required for this rate request to March 1, 1991. In the event the PSC does not establish permanent rates by January 1, 1991, temporary rates will be put in effect as of that date, with permanent rates to become effective no later than March 1, 1991. The parties to the 1989 Agreement have agreed to negotiate a multi-year rate plan, including incentive return mechanisms, with the objective of improving the Company's financial condition and the predictability of future rates. Irrespective of these negotiations, the parties have agreed that any costs deferred pursuant to the maintenance of the specified interest coverage targets discussed above or other costs deferred pursuant to the 1989 Agreement, in each case plus carrying charges, will be recovered in rates over a period no longer than three years beginning January 1, 1991, subject to an annual cap equivalent to two percent of operating revenues (approximately $50 million per year). The total amount of deferred costs to be recovered is not limited. The Company anticipates that, based on current forecasts, total costs deferred in order to maintain specified interest coverage targets discussed above, net of available cash surcharges equivalent to transmission and net resale revenues, will not exceed $100 million including carrying charges, with the preponderance of such deferrals expected to occur in 1990. The Company can provide no assurance as to the outcome of the rate plan negotiations, the level and quality of earnings that may be ultimately authorized or the Company's ability to earn the authorized equity return established.

As discussed in Note 10 "Nuclear Operations" there are a number of outstanding regulatory issues affecting the Company, including the Unit 1 prudence investigation, Unit 2 Settlement cap issues, Unit 2 contractor litigation issues and Unit 2 operating prudence issues. A goal of the 1989 Agreement is the ultimate resolution of these issues, either by negotiation or by the PSC if negotiations are not conclusive. The PSC must render a final decision no later than March 1, 1991. The Company can provide no assurance as to the outcome of the negotiations or the PSC's approval thereof, or the impact that the resolution of these issues will have on the Company's financial condition or results of operations. The Company and cotenant companies have negotiated and reached resolution on Unit 2 Settlement cap, contractor litigation, operating prudence issues and future operating and maintenance expense levels (See Note 10. "Unit 2 Ratemaking and Cost Settlement").

The Company has been studying the advantages and disadvantages of continuing the operation of Unit 1. Pursuant to the 1989 Agreement, the Company will further develop the study in good faith consultation with the parties to the 1989 Agreement and submit it to the PSC no later that February 28, 1990. The Company also will submit to the PSC and provide to the parties to the 1989 Agreement, on or before June 1, 1990, a study of the advantages and disadvantages of a separation, sale or other action with respect to the Company's gas business, and further develop that analysis in cooperation with the PSC Staff. The Company is unable to predict the results of these studies, what action may be initiated based upon such results or the impact that such results will have on the Company's financial condition or results of operations.

NOTE 12. 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 1990 through 1994 will require approximately $1.85 billion, excluding AFC, nuclear fuel and certain overheads capitalized. For the years 1990 through 1994, the estimates are $364 million, $413 million, $388 million, $354 million and $332 million, respectively.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1990, 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 ..	2007	915,000	$15,365,000
St. Lawrence—hydroelectric project ..	2007	104,000	1,248,000
Blenheim-Gilboa—pumped storage generating station	2002	395,000(a)	8,523,000
FitzPatrick—nuclear plant	year-to-year basis	77,000(b)	6,231,000
		1,491,000	$31,367,000

(a) 270,000 kw beginning May 1990.
(b) 19,000 kw for summer of 1990; 40,000 kw for winter of 1990-91.

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 $52.8 million, $46.3 million and $57.2 million for the years 1989, 1988 and 1987, respectively.

Under the requirements of the Federal Public Utility Regulatory Policies Act, the Company is required to purchase power generated by Qualifying Facilities, as defined therein. Approximately $131 million was paid to Qualifying Facilities in 1989 for 2,033,000,000 kwh of energy and associated capacity. Through December 31, 1989, 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. The amount of the commitment and the available capacity are dependent upon the ultimate completion of these projects. Generally, the Company must only pay for energy delivered.

Lease Commitments: The Company leases certain property and equipment which meet the accounting criteria for capitalization. Such leases, having a net book value of $59.3 million and $65.9 million at December 31, 1989 and 1988, 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 $622 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 1990-1994 range between $23 million and $33 million.

Sale of Customer Receivables: The Company has an agreement whereby it can sell an undivided interest in a designated pool of customer receivables including accrued unbilled electric revenues up to a maximum of $200 million. At December 31, 1989, $171 million of receivables were sold under this agreement. An additional $29 million was sold in January 1990. 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: 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 Unit 2. The amount of damage claimed was not specified.

Following initial dismissal of the complaint, the plaintiffs filed a second amended complaint in January 1989, again purporting to state claims 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 Unit 2. The defendants again made motions to dismiss the action.

On May 19 and 25, 1989, the Court rendered decisions granting the defendants' motions and dismissed all counts of the complaint. The Company is unable to predict whether the plaintiffs will commence an action in state court covering the claims governed by state law.

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 obligations.

Anti-Trust Action: In December 1987, Long Lake Energy Corporation (Long Lake) filed an action in the United States District Court for the Southern District of New York, subsequently amended in May 1988, asserting claims under Section 2 of the Sherman Act and New York's Donnelly Act. The complaint alleges that the Company interfered with Long Lake's attempts to license hydroelectric projects with the FERC. In July 1988, the Company moved for summary judgment which was subsequently denied by the Court without prejudice to its renewal at the close of the discovery process. The Company has denied the substantive allegations of the complaint and is contemplating renewal of its motion for summary judgment when discovery is concluded. By letter dated November 16, 1989, Long Lake's counsel claimed damages of $214,000,000 before trebling. The complaint has not been amended to reflect this amount. Long Lake's damage study is based, among other things, on the assumption that but for the conduct alleged, Long Lake would have been awarded a license by FERC for numerous hydroelectric sites, many of which both Long Lake and the Company have competing license applications currently pending before FERC. The Company believes that it has meritorious defenses to Long Lake's claims.

The Company is unable to predict the outcome of this action or the impact, if any, on the Company's financial position or results of operations.

Leveraged Preferred Stock Tax Reimbursement: The Company issued several series of leveraged preferred stock which contain tax reimbursement provisions that may apply if certain benefits contemplated by the arrangements are lost or become unavailable to the purchasers of the issues. In July 1989, the Company was notified that the arrangements were being challenged by the Internal Revenue Service (IRS), pursuant to an audit of the purchasers' trusts for the year 1985. The Company may be liable to the purchasers for reimbursement if the IRS is successful in any manner that results in a partial or complete loss of certain tax benefits. On January 9 and 11, 1990, the Company received Indemnity Schedules from the purchasers of the Company's leveraged preferred stock series being challenged by the IRS. The Indemnity Schedules indicate a total liability of approximately $35 million for dividends paid through 1989 as calculated by the Equity Participants. The Company has issued a letter to the Equity Participants contesting the Indemnity Schedules and its potential liability to the purchasers. The Company is unable to predict whether the IRS will be successful in its challenge or the extent of the Company's financial exposure if such challenge is successful. However, the Company believes any liability arising from resolution of these issues is expected to be recovered in the ratesetting process.

Environmental Issues: The Company is currently conducting a program to investigate and restore, as necessary to meet environmental standards, certain properties associated with a former gas manufacturing process and other properties which the Company has learned may be contaminated with industrial waste as well as investigating potential industrial waste sites to which it may be determined the Company contributed. The Company has been advised that various Federal, state or local

agencies currently believe that certain properties warrant investigation. The Company is associated with approximately 65 identified sites, of which 35 are Company-owned. Of the 35 Company-owned sites, 24 are coal gasification sites and 11 are industrial waste sites. The 30 remaining sites with which the Company is associated are generally alleged to be industrial waste sites. The Company can provide no assurance that additional sites with which it is or may be associated with will not be identified in the future as requiring investigation or remediation.

The Company's investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) determine the extent, rate of movement and concentration of pollutants, and (3) if necessary, determine the appropriate remedial actions required for site restoration. Site investigations may also include, where appropriate, identification of other parties that the Company believes should bear some, if not all, of the cost of remediation. After site investigations have been completed, the Company will be able to determine the remedial actions necessary and the attendant costs for restoration. The Company has not yet undertaken any remedial actions at any identified sites, nor have responsible regulatory agencies approved any of the Company's submitted remediation plans. Therefore, the ultimate cost of remedial actions may substantially change as investigation and remediation progresses.

The Company has completed various phases of studies on six Company owned sites and has submitted those studies to the appropriate regulatory agency. Based upon the findings of those studies and preliminary internal assessments of other sites the Company believes may require some level of remediation, total expenditures for Company owned sites are estimated to approximate $104 million through 1997. With respect to sites with which the Company is associated, total costs to investigate and remediate these sites are estimated to be approximately $103 million through 1997, of which the Company's share may approximate $13 million. Actual Company expenditures for these sites is dependent upon the total cost of investigation and remediation, as well as the determination of the Company's share of responsibility for such costs. The Company believes that costs incurred in the investigation and restoration process are recoverable in the ratesetting process.

Tax Assessments: The Internal Revenue Service (IRS) has completed examinations of the Company's Federal income tax returns for 1981 through 1984. The IRS has proposed various adjustments to the Company's Federal income tax liability for these years which could increase Federal income tax expense by approximately $10.0 million before assessment of penalties and interest. The Company is vigorously contesting the proposed adjustments, and believes that the ultimate resolution thereof will not have a material effect on the Company's financial position or results of operations. The Company also believes that assessments, if any, are generally recoverable in rates.

The Company is also at various stages of examination by the State of New York for sales tax and other state taxes. The Company believes that the resolution of these examinations will not have a material impact on the Company's financial condition or results of operations, and that any assessments ultimately sustained will be recoverable by the Company through the ratesetting process.

NOTE 13. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income (loss) and earnings (loss) per common share by quarters for 1989, 1988 and 1987 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.

In thousands of dollars

Quarter ended	Operating revenues	Operating income	Net income (loss)	Earnings (loss) per common share
December 31, 1989	$734,038	$ 88,139	$ 9,068	$ (.01)
1988	678,858	65,918	(3,808)	(.12)
1987	653,906	114,509	(32,649)	(.36)
September 30, 1989	$612,971	$101,546	$ 36,322	$ .19
1988	608,393	113,496	52,297	.31
1987	556,845	98,958	44,829	.25
June 30, 1989	$710,582	$ 87,908	$ 34,147	$ .17
1988	702,678	126,718	46,823	.27
1987	624,628	102,810	48,711	.29
March 31, 1989	$848,452	$134,366	$ 71,246	$ .44
1988	810,524	170,221	113,502	.77
1987	788,051	169,121	(618,105)	(4.96)

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 1989, 1988 and 1987 the Company accrued $14.5 million ($.08 per common share), $7.5 million ($.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).

In the first quarter of 1987, the Company recorded a net loss associated with the Unit 2 disallowance of $755 million relating to its adoption of SFAS No. 90. The proforma amounts, to reflect the retroactive application for SFAS No. 90 for the first quarter of 1987 for Net loss and Loss per common share, are $3.1 million and $.13, respectively. An additional $78 million was written off in the fourth quarter of 1987 based upon a revision of the Unit 2 cost estimate. See Note 10.

NOTE 14. Subsequent Events (Unaudited)

On February 13, 1990, the Company received a report discussing the results of an inspection conducted at Units 1 and 2 by NRC site resident inspectors in September and October 1989. The report identified a number of potential deficiencies at Unit 1, including inadequate management oversight of system "walkdowns". Based upon the inspectors' concern of inadequate management oversight, coupled with other system specific concerns, an enforcement conference has been requested by the NRC Region I Administrator to further discuss these findings and assess their safety significance. The Company is correcting the deficiencies identified in the report. The Company is unable to predict what actions may be taken by the NRC as a result of the enforcement conference, but does not believe that the outcome will have an effect on the restart of Unit 1.

The Company was also notified by the NRC Region I Administrator that as a result of this same inspection a Notice of Violation has been issued with respect to Unit 2. The Notice of Violation, which has been categorized as Severity Level IV and thus may result in a fine, was precipitated by the resident inspectors' conclusion that Unit 2 personnel had violated post-maintenance testing requirements of the unit cooler for a control room. The Company must provide a response to the NRC within thirty days of receipt of the report.

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 dividends were paid on March 31, June 30, September 30 and December 31. Common stock dividends were paid on March 31 and June 30, 1989 and subsequently suspended due to the uncertainties discussed below. The Company presently estimates that none of the 1989 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.

1989	Dividend paid per share	Price range High	Low
1st Quarter	$ .30	$13¾	$11½
2nd Quarter	.30	12⅛	10¾
3rd Quarter	—	14⅜	11⅛
4th Quarter	—	14¾	13⅜
	$ .60		
1988			
1st Quarter	$ .30	$14	$12
2nd Quarter	.30	15½	12⅜
3rd Quarter	.30	15⅜	12⅞
4th Quarter	.30	14¼	12½
	$1.20		

On August 31, 1989, the Board of Directors, after considering the uncertainties facing the Company, including the level and timing of future rate relief, the restart of Unit 1 and the risks associated with a number of outstanding regulatory proceedings, determined to omit the third quarter common stock dividend. No fourth quarter common stock dividend was paid. Resumption of payment of the common stock dividend will depend on the resolution of issues affecting the long-range financial condition of the Company, including the return to service of Unit 1 and the effect, if any, of such resumption of common stock dividends on the 1989 Agreement, as discussed in Note 11 of Notes to Consolidated Financial Statements. Pursuant to the 1989 Agreement, if the Company resumes payment of common stock dividends prior to Unit 1 being fully returned to service (and achieving an average 75% capacity factor for a period of thirty consecutive days) any other party to the 1989 Agreement may withdraw therefrom and recommence litigation of the rate case and the regulatory proceedings covered by the 1989 Agreement. The Company can provide no assurance that when Unit 1 has returned to service its Board of Directors will thereupon determine to resume common stock dividend payments or as to the level at which they might be resumed.

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, although the Company plans to issue $100 million of Preference Stock during 1990.

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 152,000 stockholders owned common shares of Niagara Mohawk and about 6,500 held preferred stock.

Size of holding (Shares)	Total stockholders	Total shares held
1 to 99	53,089	1,791,505
100 to 999	88,426	24,783,311
1,000 or more	10,175	109,524,838
	151,690	136,099,654

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, 1989 and 1988, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1989, 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 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 1989 and 1988 financial statements.

As discussed in Note 12, the Company is a defendant in a lawsuit alleging violations of certain federal and state antitrust statutes. Management is unable to predict whether the outcome of this action will have a material effect on its financial position or results of operations. Accordingly, no provision for any liability that may result upon resolution of this uncertainty has been made in the accompanying 1989 financial statements.

Price Waterhouse

Syracuse, New York
January 25, 1990

Electric and Gas Statistics

ELECTRIC CAPABILITY

At January 1,	1990	%	1989	1988
	Thousands of kilowatts			
Thermal:				
Coal fuel				
Huntley, Niagara River	715	9	715	715
Dunkirk, Lake Erie	585	8	560	560
Total coal fuel	1,300	17	1,275	1,275
Residual oil fuel				
Albany, Hudson River**	400	5	400	400
Oswego, Lake Ontario***	1,654	22	1,571	1,572
Roseton, Hudson River	300	4	300	300
Middle distillate oil fuel				
8 Combustion turbine units	230	3	237	237
Total oil fuel	2,584	34	2,508	2,509
Nuclear fuel				
Nine Mile Point, Lake Ontario(1)	1,050	14	1,054	610
Purchased—firm contract				
Power Authority—FitzPatrick, Lake Ontario	77	1	53	59
Total nuclear fuel	1,127	15	1,107	669
Independently owned sources	171	2	121	97
Total thermal sources	5,182	68	5,011	4,550
Hydro:				
Owned and leased hydro stations (74)	680	9	695	695
Purchased—firm contracts:				
Power Authority—				
Niagara River	915	12	1,077	1,076
St. Lawrence River	104	2	—	—
Blenheim-Gilboa Pumped Storage Plant	395	5	295	270
Other	298	4	294	285
Total hydro sources	2,392	32	2,361	2,326
Total capability*	7,574	100	7,372	6,876
	1989		1988	1987
Electric peak load during year	6,376		6,220	5,780

*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.

(1) Nine Mile Point Unit No. 1 (representing 610,000 KW) has been out of service since December 1987. See Note 10.

ELECTRICITY GENERATED AND PURCHASED

	1989	%	1988	%	1987	%
	Millions of kw-hrs.					
Thermal:						
Generated						
Coal	9,013	24	7,894	21	7,185	18
Oil	6,470	17	7,444	19	4,256	11
Nuclear	1,762	5	1,460	4	4,753	12
Natural gas	2,456	6	1,070	3	1,785	4
Purchased–						
Nuclear from Power Authority	387	1	306	1	700	2
Independently owned sources	830	2	612	1	359	1
Total thermal	20,918	55	18,786	49	19,038	48
Hydro:						
Generated	3,675	10	3,171	8	3,396	8
Purchased from Power Authority	6,721	17	7,014	18	7,378	19
Independently owned sources	1,203	3	978	3	1,017	3
Total hydro	11,599	30	11,163	29	11,791	30
Other purchased power—various sources	5,765	15	8,192	22	8,583	22
Total generated and purchased	38,282	100	38,141	100	39,412	100

ELECTRIC STATISTICS

	1989	1988	1987
Electric sales *(Millions of kw-hrs.)*			
Residential	10,357	10,099	9,655
Commercial	11,432	11,182	10,718
Industrial	12,184	11,745	10,922
Municipal service	228	237	235
Other electric systems	1,195	1,732	4,154
	35,396	34,995	35,684
Electric revenues *(Thousands of dollars)*			
Residential	$ 842,523	$ 805,523	$ 739,034
Commercial	874,187	827,918	783,103
Industrial	486,108	458,332	435,518
Municipal service	42,294	41,231	40,603
Other electric systems	58,056	60,214	118,021
Miscellaneous	115,494	150,514	53,912
	$2,418,662	$2,343,732	$2,170,191
Electric customers *(Average)*			
Residential	1,345,033	1,324,367	1,307,946
Commercial	143,232	140,237	138,193
Industrial	2,334	2,322	2,374
Other	3,163	3,182	3,400
	1,493,762	1,470,108	1,451,913
Residential *(Average)*			
Annual kw-hr. use per customer	7,700	7,626	7,382
Cost to customer per kw-hr.	8.14¢	7.98¢	7.65¢
Annual revenue per customer	$626.40	$608.23	$565.03

GAS STATISTICS

	1989	1988	1987
Gas sales *(Thousands of dekatherms)*			
Residential	52,893	51,065	48,054
Commercial	23,152	23,951	23,520
Industrial	2,612	4,274	7,242
Other gas systems	2,020	2,158	2,504
Total sales	80,677	81,448	81,320
Transportation of customer-owned gas	33,769	27,244	21,862
Total gas delivered	114,446	108,692	103,182
Gas revenues *(Thousands of dollars)*			
Residential	$317,532	$289,026	$280,092
Commercial	125,912	119,929	121,145
Industrial	12,309	19,008	29,733
Other gas systems	9,272	9,363	8,802
Transportation of customer-owned gas	19,831	13,841	11,551
Miscellaneous	2,525	5,554	1,916
	$487,381	$456,721	$453,239
Gas customers *(Average)*			
Residential	424,494	417,360	411,566
Commercial	35,925	35,017	33,974
Industrial	280	323	395
Other	2	2	2
Transportation	516	403	184
	461,217	453,105	446,121
Residential *(Average):*			
Annual dekatherm use per customer	124.6	122.4	116.8
Cost to customer per dekatherm	$6.00	$5.66	$5.83
Annual revenue per customer	$748.02	$692.51	$680.55
Maximum day gas sendout *(dekatherms)*	802,909	818,128	758,914

Directors

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

Lawrence Burkhardt, III *(F)*
Executive Vice President, Nuclear Operations

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

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

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

John M. Endries *(G)*
President

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

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. *(A, B, E)*
Chairman of the Board and Chief Executive Officer, Fay's Incorporated, 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 *(A, E, F)*
Chairman, Market Risk Committee, Morgan Guaranty Trust Company of New York, New York

Steven B. Sample *(D, F)*
President, University at Buffalo

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
G. Member of the Self-Assessment Committee

Officers

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

John M. Endries
President

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

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

William E. Davis
Vice President, Corporate Planning
(Effective 2/1/90)

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

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 D. Woods, Jr.
Vice President, Human Resources

Arthur W. Roos
Treasurer
(Effective 3/1/90)

Corporate Information

Annual Meeting
The annual meeting of shareholders will be held at the Everson Museum of Art, 401 Harrison Street, Syracuse, N.Y. 13202 at 10:30 a.m. Tuesday, May 1, 1990. 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.)

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, 1990 by writing the Investor Relations department at 300 Erie Boulevard West, Syracuse, N.Y. 13202.

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

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:
First Chicago Trust Company of New York
30 West Broadway, New York, N.Y. 10007-2192
(Effective 6/1/89)

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

Stock Exchanges–Ticker Symbol: NMK
Common Stock and Certain Preferred Series:
Listed and traded on the New York Stock Exchange.

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

Bonds: Traded on the New York Stock Exchange.

NIAGARA MOHAWK
300 Erie Boulevard West
Syracuse, New York 13202

50-220 9004300319

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