We will become the most responsive and efficient energy services company in the Northeast to achieve maximum value for customers, shareholders and employees

NIAGARA MOHAWK POWER CORPORATION

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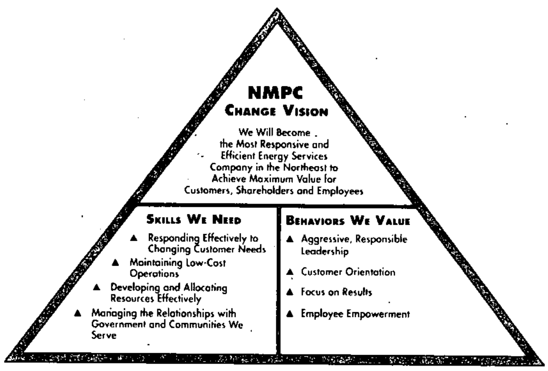


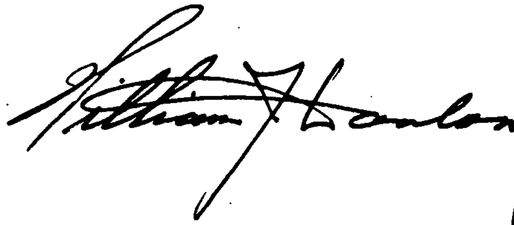
Cover Rationale

As part of Niagara Mohawk's ongoing self-assessment program, a new vision for the corporation was developed and articulated late in 1990. It describes the company we aspire to be, and defines the skills we will need and the behaviors we will value to reach our goal. This vision already is becoming an integral part of our internal communications. We now are communicating our vision and our efforts to achieve it externally to those key audiences who will benefit by our actions – investors, customers, regulators and the communities we serve.

Highlights of 1990

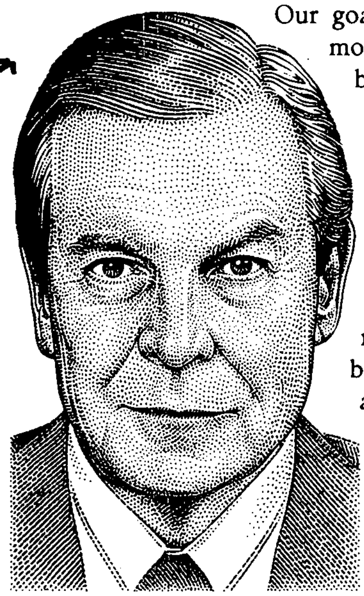
	1990	1989	% Change
Total operating revenues	$ 3,154,719,000	$ 2,906,043,000	8.6
Income available for common stockholders	$ 40,578,000	$ 105,601,000	(61.6)
Earnings per common share	$ .30	$ .78	(61.5)
Dividends per common share	–	$ .60	–
Common shares outstanding *(average)*	136,100,000	136,052,000	–
Utility plant *(gross)*	$ 8,702,741,000	$ 8,324,112,000	4.5
Construction work in progress	$ 442,982,000	$ 387,520,000	14.3
Gross additions to utility plant	$ 431,579,000	$ 413,492,000	4.4
Public kilowatt-hour sales	34,033,000,000	34,201,000,000	(.5)
Total kilowatt-hour sales	35,544,000,000	35,396,000,000	.4
Electric customers at end of year	1,520,000	1,504,000	1.1
Electric peak load *(kilowatts)*	5,792,000	6,376,000	(9.2)
Natural gas sales *(dekatherms)*	78,617,000	80,677,000	(2.6)
Natural gas transported *(dekatherms)*	34,242,000	33,769,000	1.4
Gas customers at end of year	475,000	466,000	1.9
Maximum day gas deliveries *(dekatherms)*	714,122	802,909	(11.1)

Letter to shareholders:



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

February 20, 1991



There is an adage in business that the only constant is change. Never was that more evident for Niagara Mohawk than in 1990. We instituted a number of significant changes in the past year, building on a framework for financial improvement constructed in 1989. Some changes were made rapidly while others took longer, and some are yet to come.

Our goal in managing these changes is a stronger, more competitive Niagara Mohawk. We want to be among the best in our industry.

A measure of our progress will be our ability to resume payment of dividends on your shares of common stock. Both we and our regulators view another measure of success as long-term, sustained improvement in operations.

Although our financial results did not meet expectations, the groundwork has been laid for significant improvement in 1991 and beyond.

Earnings for 1990 were $40.6 million or $.30 per share, after the impact of a $140 million ($.68 per share after tax) write-off of disallowed costs associated with nuclear operations. Earnings for 1990 were aided by our August 1989 regulatory agreement that provided for expense deferrals tied to our self-assessment program.

Also adversely affecting earnings were expenses associated with the extended outages at both the company's nuclear plants, warmer than normal weather in the fourth quarter and a further write-off of the company's investment in its uranium mining subsidiary.

Earnings were $105.6 million or $.78 per share in 1989.

Milestones in 1990

The August 1989 regulatory agreement was the beginning of a comprehensive program of change for Niagara Mohawk. Several areas requiring particular attention over the next several years were identified. Substantial progress was made on a number of fronts:

- In July, we returned Nine Mile One to service following 31 months of intensive work and regulatory scrutiny. The plant reached full power in October.
- We negotiated a new three-year labor agreement with the International Brotherhood of Electrical Workers locals covering 8,400 union employees.
- Through our self-assessment program, we focused on improvements in operation that will enhance our ability to control expenses and respond to changing customer needs.
- Our reorganization continues. Several outstanding individuals joined our board and senior management team and will assist us in this process.

The year was not without difficulties and disappointments. Foremost was the omission of dividends on common stock throughout the year. In late November, the regulatory requirement of returning Nine Mile One to service was satisfied, but continuing uncertainties did not make it prudent to recommend dividend payment to the Board of Directors. However, it is our intention to recommend reinstatement of a dividend at the earliest time that financial and operational conditions warrant.

A Complex Regulatory Arena

Commanding a great deal of attention throughout 1990 were the complex and often protracted negotiations with regulators and other parties concerning rates, nuclear issues and other matters.

During the year, the Public Service Commission approved an agreement between Niagara Mohawk and several parties that closed out a number of issues involving Nine Mile Two construction and outages. This agreement, while having only a small impact on our financial or operational condition, puts the construction era of Nine Mile Two officially behind us.

In December, the PSC approved a temporary increase in revenues of $190 million, or about 6.5 percent. This was in keeping with the August 1989 regulatory agreement that required temporary rates to be put into effect by January 1, 1991 if final resolution of the rate case and other matters was not achieved.

In February of this year, we reached an agreement-in-principle with the Department of Public Service and other parties that would, if approved by the PSC, settle rates and other regulatory issues through December 1992.

We will notify you of the outcome of Commission consideration of the agreement-in-principle, including the financial implications for the company. We do not expect a decision from the PSC before June. We can offer no assurance that the Commission will approve the agreement, although we believe it is in the best interest of customers and shareholders.

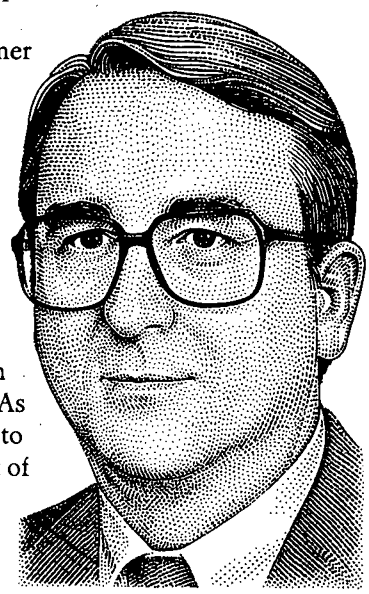
All of these matters were negotiated with the PSC, the state Attorney General, the Consumer Protection Board, Multiple Intervenors and others. We followed both the spirit and the letter of the 1989 regulatory agreement, and have met all the milestones it established.

Our responsibility is to seek fair treatment that balances the interests of our customers and shareholders. Performance goals embodied in the new agreement-in-principle, if achieved, would indeed enhance results for both. This inventive approach to regulatory policy represents a forward step in our relations with regulators and an innovative feature compared to national regulatory trends.

John M. Endries
President

Reorganization Continues

By July 1, we will have completed our reorganization into strategic business units, each fully accountable for its performance in support of corporate goals.



Our business units will be Gas Customer Service, Electric Customer Service, Electric Supply and Delivery, and Nuclear Operations.

Each will have control over all key aspects of its business to achieve maximum efficiency and take advantage of opportunities for growth. Centralized services will continue to be maintained in key functions such as corporate planning, human resources, finance and corporate services, and legal and corporate relations.

We believe the SBU structure is the best option to meet the challenges of the coming years. These include increasing competition in the industrial markets, meeting environmental responsibilities, the push for open access to transmission, the growth in energy demand and the multitude of possible methods to meet it. As we work to meet such challenges, the SBU structure is expected to increase accountability and push decision-making closer to the point of customer contact.

A Vision for the 1990s

Much of what has transpired in the past year was the direct result of our PACE program for self-assessment. Change is being managed. To guide us in this effort, we have developed and articulated a new vision for Niagara Mohawk.

We will become the most responsive and efficient energy services company in the Northeast to achieve maximum value for customers, shareholders and employees.

We are strengthening the skills required to achieve this goal. Highly valued behaviors – responsible leadership, customer orientation, a focus on results and employee empowerment – will be stressed.

The intent is not to change the business we are in. The business, in many ways, is changing already. Rather, our efforts are focused on changing the *way* we do business in this more competitive environment.

We are determined to have a corporate culture that stresses efficiency, accountability, quality and value. This will require renewed focus, and the men and women of Niagara Mohawk are committed to making it happen. The benefits of this effort are shared: for the customer, quality products and services at fair prices; for the shareholder, a reasonable return on investment; and for the employee, a stable, nurturing work place that rewards innovation, excellence, and performance.

Niagara Mohawk's corporate vision is a simple statement of our goal to become the best utility in the Northeast. This is our ultimate standard as we work through the gradual steps of our recovery. It requires us to be flexible – willing to accept and embrace change.

Success in building the value of Niagara Mohawk to its customers, shareholders and employees will increase not by what we say, but by what we accomplish. We are instituting incentive programs to sharpen the focus on achieving positive results.

The actions we have taken, and those we have planned, are outlined further on the pages that follow. We are a better company than we were one year ago. We are committed to being better still one year from now.

Your support of these efforts is appreciated.

Vision

We will become the most responsive and efficient energy services company in the Northeast to achieve maximum value for customers, shareholders and employees.

During the development of our vision for change, a number of skills required for success were identified. We must be able to respond to changing customer needs and maintain low cost operations. We have to be effective in developing and allocating our resources, as well as in managing relationships with government and the communities we serve.

These skills require certain behaviors – both individually and as a corporation – that we are determined to encourage. We will seek and demonstrate aggressive, responsible leadership. Niagara Mohawk people must have a customer orientation and focus on results. And the company must empower its employees, giving them the freedom and the tools they need to make the decisions necessary to perform their jobs efficiently and effectively.

It will not be easy, nor will it happen overnight. Achieving our vision will require a change in corporate culture, as well as strategic changes in structure.

Reorganization

Very early in our self-assessment, we examined closely two basic options for organization of the company – the functional model that had been in place and a business unit structure.

The functional model divided the company into groups that perform similar work, such as services, finance and operations. When each function has a simple mission and can work with relative independence the model works well. For many years that was the case at Niagara Mohawk.

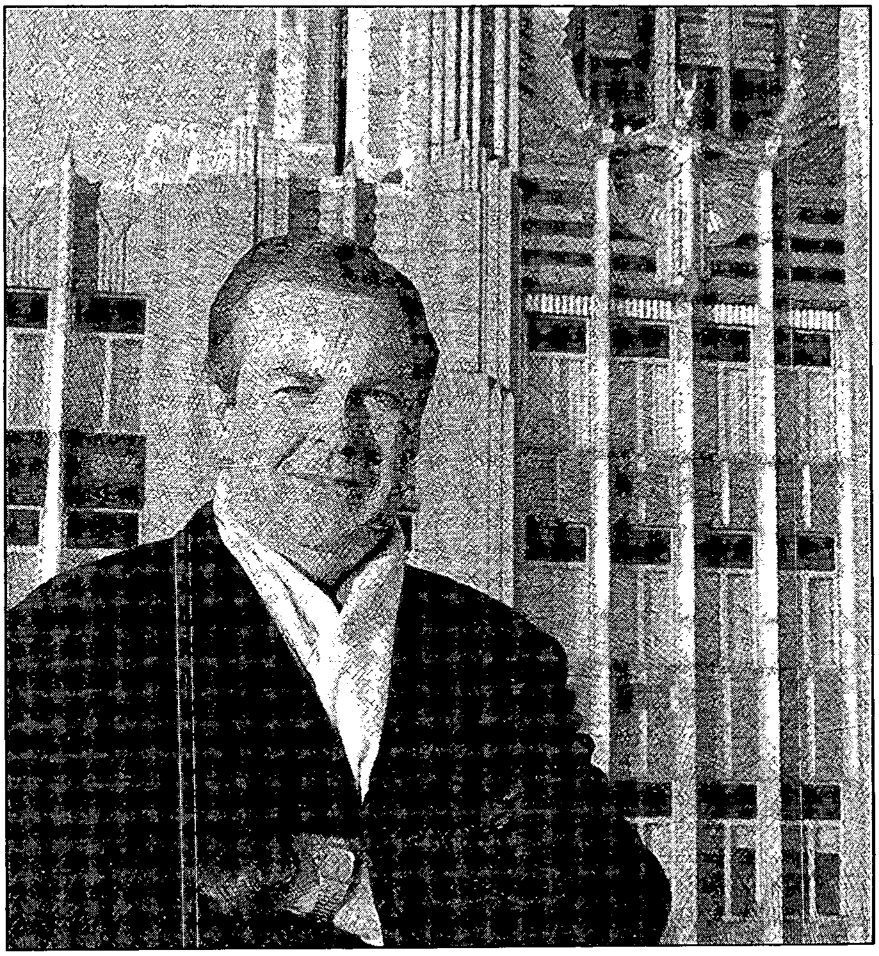
The strategic business unit model divides an organization along natural lines of business, such as generation and customer service. Within each unit are placed an appropriate range of support functions – employee relations, planning, budgeting – that allow the unit to essentially act as a stand-alone business.

A group of shared services is maintained for economies of scale, as in data processing; or where there is need for a corporate direction, as in strategic planning or external affairs.

Each business unit is given

Focusing on Results:

"I want the people of Niagara Mohawk to have a bias for action. Always looking for a better way. Anticipating change and being ready to deal with it. An urge to get it done. With that sort of ethic, the results will come. And everybody will benefit from it — customers, shareholders and employees."



control of, and accountability for, key aspects of its business, putting it in a position to achieve maximum efficiency and responsiveness to its customers.

Given the evolving nature of the environment in which this company now operates and the goals established in our vision, it became clear that the strategic business unit structure was the appropriate option for Niagara Mohawk. The reasons are simple. We want to increase our responsiveness to meeting customer needs. We intend to place with our employees greater responsibility and authority to make the decisions necessary to satisfy the customer. And we intend to do this profitably. Strategic business units will help us do this.

We are creating four strategic business units – electric customer service, gas customer service, electric supply and delivery, and nuclear operations.

Our reorganization aligns other functions – human resources, finance and corporate services – into strategic support departments to take advantage of economies of scale. This new structure changes not only lines of responsibility for operational activities, but also redefines the roles of the chairman and CEO, and the president of the company.

Business unit organizations, with lines of responsibility and accountability clearly defined, will allow the chairman to focus on establishing the broad direction of the company. A major component of this activity requires an external focus, including helping the company better manage its relationships with the governments and communities we serve. To support this activity, Legal and Corporate Relations, Corporate Planning and Corporate Audits now report directly to the chairman.

The role of the president now has a primarily operational focus. Reporting to him are the four strategic business units and allied corporate support departments.

The change in reporting relationships and the establishment of the corporate support functions have been completed. Full development of the strategic business units is scheduled to be complete by July 1.

One of the goals of establishing the business units – particularly the electric and gas customer service units – is to enhance our ability to serve customers, the very foundation of our business.

To that end, our self-assessment process includes a special initiative that is examining the requirements of meeting the needs of our customers. We intend to develop service strategies that recognize and address the needs of specific customer groups.

While still in the research phase, this initiative is examining the product and service attributes that drive customer satisfaction. It will identify areas of performance that present the greatest opportunity for improving customer satisfaction.

Reorganization is changing the way we are structured, and the way we serve our customers. It also is bringing change in personnel, as well. We are identifying the best people within Niagara Mohawk, and are moving them into positions that take full advantage of their talents.

We also have looked outside for expertise in particular areas, recruiting talented people who bring a new perspective to our organization. In the past year alone, we have added five new members to our senior management team.

And in January, we added two new members to our Board of Directors. They bring extensive backgrounds in consumer affairs and environmental matters – areas already identified as critical to the success of Niagara Mohawk throughout the 1990s. Douglas Costle served for six years as the administrator of the Environmental Protection Agency. Dr. Bonnie Guiton served two U.S. Presidents in three separate appointments, most recently as special advisor for consumer affairs to the Bush administration.

Demand-Side Management

An ongoing area of attention for Niagara Mohawk, our regulators and the industry in general is the continued push for demand-side management as a means of meeting and controlling the growing demand for energy.

Late in 1989, Niagara Mohawk launched a program to promote energy efficiency among the more than 3.5 million people in our service territory. The premise behind this initiative is that helping customers use less electricity, or use it more efficiently, often costs less than building new power plants. The cost of saving a kilowatt-hour through Niagara Mohawk's DSM programs is less than the cost of generating the same kilowatt-hour.

Because DSM programs reduce electricity usage, they reduce Niagara Mohawk's revenues and production expenditures. New regulatory incentives have not only been designed to protect the company from losses of net revenue, but also to allow us to earn a profit on these new programs.

The Public Service Commission has approved a mechanism through which we are allowed to recover program costs, lost margins and an additional financial incentive for cost-effective DSM program implementation. The effect in the short run is an increase in the cost of a kilowatt-hour to our customers, but the increase is modest and participants will more than compensate for that increase through reductions in energy usage. In the long run, the program is designed to enable everyone to save compared to the alternatives.

The economic incentives are a way to reward shareholders for the company's investment in conservation and load management.

There are now 12 core programs under way addressing all classifications of customer service, identified and promoted collectively as the Niagara Mohawk **Reducing Plan.**™

By the end of 1990, we estimate these programs reduced energy consumption by more than 110,000 megawatt-hours annually.

One of the larger DSM programs to date offers free conservation measures to residential customers who use electricity to heat their water. Each participant can request a water heater insulation blanket, water pipe insulation and faucet aerators that would reduce their electricity use by roughly 1,000 kilowatt-hours per year – a $70 reduction.

So far, over 75,000 customers have received these kits. We intend to enroll over 175,000 customers by the end of 1992. In the commercial and industrial markets, over 600 customers received incentives in 1990 for installation of energy-saving lighting measures that should reduce their consumption by more than 33,000 megawatt-hours annually.

We welcome this opportunity to satisfy our customers' needs while building value for our shareholders. To that end, we are strengthening our DSM capabilities for 1991 and beyond. Our 1991-92 DSM plan calls for three additional large-scale programs, bringing our total to 15 programs with the potential to achieve a reduction of 60 to 70 megawatts of needed electric capacity by the end of 1992.

Nuclear Operations

In the early morning hours of July 29, a chain reaction was sustained within the reactor of Nine Mile One, marking the beginning of the end of a 31-month outage that brought a cloud over what had been one of the finest records of performance in the nuclear industry.

Long hours and hard work were required to complete over 30,000 work items during shutdown. The level of regulatory scrutiny was unprecedented in our history, however, the Nuclear Regulatory Commission agreed with our assessment approving restart.

After a conservative and thorough power ascension program, Nine Mile One reached full power in late October, providing more than 600 megawatts to the New York state power grid.

Our decision to proceed with restart was based on a number of factors, the primary ones being safety and economics. We are confident that Nine Mile One can and will operate safely and economically.

The economics for continued operation were evaluated carefully by the company and state regulators. We conducted an economic analysis of the plant, developing a number of scenarios to evaluate continued operation versus early decommissioning. We concluded, as did our regulators, that the plant continues to provide value to our customers, our shareholders and New York state, based on anticipated capacity factors and capital improvement costs.

Nine Mile Two continued to show improved performance in its third year of commercial operation, including a 100-day run just prior to shutdown for its first refueling. The plant came off-line in September for its first refueling and maintenance, and returned to service in January.

Both nuclear plants remain on the NRC's list of facilities requiring close regulatory monitoring, however, the NRC recently noted that performance continues to improve. The way we plan to get our plants off that list is through a sustained period of excellent performance from the units and the people who operate them. We initiated a business plan combined with the nuclear division's reorganization undertaking as major steps toward that goal.

The senior management within the nuclear division has been strengthened. A new process of accountability was instituted, empowering employees to carry out their jobs and holding them responsible for their actions.

The company is developing and implementing programs to simplify procedures, streamline corrective action programs, establish a career development program and increase leadership training.

Our efforts are beginning to bear fruit. This January, the NRC wrote in a letter to the company that "... the licensee has continued to improve performance in all previously identified problem areas." In February, we received notice from the NRC that the final restrictions to continued, routine full power operation of Nine Mile One had been lifted. Regulators based their decision on a trend of improved performance and our demonstration of the capability to safely operate our plants.

From our study of the economic benefits of operating Nine Mile One, it's clear that nuclear power provides a cost-effective hedge against the escalation of fossil fuel prices. At the time the study was compiled, we knew that clean air legislation being considered on the federal level would likely result in increased costs of operating fossil-fueled plants. That legislation was enacted. But a more profound exclamation point to that study was the August 2 invasion of Kuwait by Iraq, and the resulting fear and volatility in world oil markets.

Generation Capacity

Our ability to meet electrical demand goes beyond nuclear power, of course. Prudent, long-term planning has assured us that Niagara Mohawk will not be dependent on any one fuel source. Our diversified generating capabilities – coal, oil, natural gas, nuclear and hydroelectric – combined with long-term, cost-effective purchased power and conservation efforts, will allow us to meet our customer needs for years to come without falling prey to the whims of uncertain fuel markets.

In 1990, our fossil fuel and hydroelectric generating stations' performance, combined with nuclear and long-term contracts for purchased power, allowed us to offer our customers some of the lowest rates in the Northeast.

Niagara Mohawk's fossil fuel stations generated more than 17.7 million megawatt-hours of electricity, once again serving as the backbone of our generation mix. The Oswego Steam Station set a new facility record, generating more than 5.6 million megawatt-hours in 1990.

We continued to make excellent use of our 74 hydroelectric stations, generating more than 4.0 million megawatt-hours during the year, up 9.5 percent over 1989 and just over four percent below the all-time hydro production record set in 1976.

Late in the year, we completed drafting relicensing applications for hydro projects, and have circulated those drafts to various state and federal regulatory agencies for comment. Relicensing applications on these projects are to be filed with the Federal Energy Regulatory Commission by the end of 1991.

Many of these facilities have been in continuous service since the 1920s. We are planning a

Building Responsiveness:

*"Niagara Mohawk will earn customer loyalty by providing reliable service and maximum energy value. We can't act on what we think customers want, or what our regulators think customers want. We have to find out from **customers** what they want, then find a way to provide it to them efficiently."*

number of renovation projects, including upgrading existing units and adding capacity totaling more than 70,000 kilowatts at sites on the Oswego, Raquette, Black, Hoosic and Hudson Rivers.

We will continue to meet the growing demand for energy through the use of our existing resources and efforts to manage customer demand and usage.

New capacity still will be necessary in this decade, however. We will meet at least part of this demand with power from independent producers – a growing source of energy throughout New York state.

In 1990, we conducted our first all-source bidding program, soliciting proposals for an additional 350 megawatts to be available by late 1994. The response was outstanding, as qualified bidders submitted 106 proposals representing more than 7,300 megawatts.

After separate reviews by independent evaluators and our own personnel, we selected two supply-side and seven demand-side projects representing a total of 441 megawatts of capacity.

Among the bids selected was a proposal to extend by 15 years the life of one of the coal-fired generating units in our own Huntley Steam Station in the town of Tonawanda in western New York. The unit, rated at 189 megawatts, went into service in 1957.

Life extension of this unit is projected to be a $130 million investment that will include a major turbine overhaul and the installation of additional environmental controls to reduce emissions further.

The great diversity among bidders was demonstrated in the range of projects selected in the final award. A second supply project – a 216-megawatt, gas-fired combined-cycle turbine planned for Guilderland, N.Y. near Albany – was submitted by a consortium of companies that include Pacific Gas & Electric of California.

Among the demand-side projects we selected are industrial lighting programs, high-efficiency electric motor replacements, even a program to "round-up" old, inefficient refrigerators from across our service territory. While such a project might sound frivolous to some, it is a very real, viable method of helping control the demand for electricity.

We now are negotiating contracts for these projects, each selected on the basis of cost, reliability, environmental impact and the probability of success.

Efforts to meet the needs of our gas customers continued throughout 1990 as well. In July, we reached agreement with CNG

Building Efficiency:

"We are building a new ethic at Niagara Mohawk that looks at cost management and service as two sides of the same coin — not competing forces. Quality service is expensive. But we must look at quality as an investment, because the ultimate cost of poor quality is even greater."

Transmission Corp., our primary gas supplier for the past 20 years, for a complete restructuring of gas service. If approved by federal regulators, the agreement provides for a range of gas supply services to be provided by CNG over a ten-year period starting this spring.

This will allow us to purchase gas transportation services from CNG and three other pipelines, providing us direct access to the gas-producing regions in the United States. In addition, we will be able to purchase contract storage from CNG. The sole provider restriction in our old agreement has been removed, enabling us to diversify our supply options.

In short, Niagara Mohawk will be able to take direct control of all its gas supply purchases to meet our market needs. This will allow us to offer our customers more options, making us more competitive in new markets and more efficient and economical in existing markets.

Late in 1989, we suffered a setback in our plans to construct a natural gas pipeline across the St. Lawrence River. The Trans York project is part of a contract signed with a Canadian supplier – our first entry into this market – to purchase 50,000 dekatherms a day from the vast reserves in Western Canada.

The Canadian National Energy Board had rejected a number of export applications, including ours. We joined our Canadian supplier in immediately appealing the decision. Subsequently, the Canadian board reversed its decision, allowing us to go forward with the project.

On the domestic side, the federal Department of Energy has approved our import application and the state Public Service Commission has issued a certificate of environmental compliance for the project. We are seeking the remaining necessary regulatory approvals and rights-of-way on both sides of the border, and we are confident approvals will be forthcoming.

Building Efficiency

A focal point of our self-assessment program has been an ongoing effort to examine the way we do business – an organizational analysis.

Working with our consultant, McKinsey & Co., we began a program known as Activity Value Analysis that examines all company operations and includes every employee of Niagara Mohawk.

AVA asks employees to examine their activities to ensure that work is necessary and being done in the most effective and efficient way. Ideas are submitted to improve work procedures, reduce costs, and suggest new activities that will increase the overall effectiveness of the corporation.

The AVA process was implemented in three cycles – nuclear and fossil generation, regional operations, and corporate support staff. Thus far, thousands of ideas have been submitted, evaluated and approved.

We have identified significant dollars in potential annual cost savings. Some of those savings will require one-time start-up costs before implementation. Others are subject to negotiation with regulators or the labor union representing nearly 8,400 Niagara Mohawk people.

The potential for significant operational improvement and cost savings is real, however. Combined with our new vision for change and reorganization efforts, we expect to be a significantly different company in the very near future.

For example, by the end of 1993, we should have a right-sized work force in the nuclear division. The reductions will include some 750 positions now filled by contractors and the gradual elimination of an additional 450 positions which includes temporaries and vacant positions.

These are only targets at this point, and could change over time depending on the needs of the business. The potential impact of the other AVA cycles or further reorganization on total employment has not yet been fully determined. But there can be no question that the effort to make Niagara Mohawk the right size is serious.

We will follow the provisions of our existing labor agreement with the International Brotherhood of Electrical Workers in dealing with represented employees who may lose their jobs as a result of these efforts.

A plan was developed for those in management who ultimately may be displaced. Our intent is to treat employees who lose their jobs in the most fair, dignified manner possible.

The results of AVA activities in regional operations and corporate departments are being compiled now, and developed into detailed implementation plans. Once approved by senior management, actual implementation of ideas from these cycles will begin in a systematic fashion.

Specific self-assessment initiatives were established to examine our strategic and operational efforts. These in-depth studies have resulted in a number of specific recommendations to improve budgeting and planning processes, customer service, employee development, teamwork and communications, and other aspects of activities for the corporation and the strategic business units.

Hydra-Co

HYDRA-CO Enterprises formed in 1981 with a mission to develop, own and operate unregulated power generation facilities that are reliable, competitively priced and environmentally compatible. Since its creation, HYDRA-CO has become a leader in the field of independent power development, ownership and operation. As an electric utility subsidiary, HYDRA-CO is required to operate within the guidelines of the Public Utility Regulatory Policy Act of 1978, which restricts its ownership of facilities to 50 percent.

As of year end 1990, HYDRA-CO was participating in the ownership and operation of 115 megawatts of waste-wood-fueled small power plants, 129 megawatts of hydro power, 101 megawatts of wind energy and 154 megawatts of gas-fueled cogeneration.

HYDRA-CO was also constructing an 80-megawatt coal-fired cogeneration facility. These facilities have a combined value of approximately $900 million and displace millions of barrels of imported oil. HYDRA-CO Operations, a subsidiary formed in 1989, has grown to 180 people and is operating plants in California, Maine, New York, Vermont and North Carolina.

Projects in which HYDRA-CO participated in 1990 generated revenues in excess of $133 million. On a consolidated basis, HYDRA-CO provided Niagara Mohawk with retained earnings in excess of $12 million.

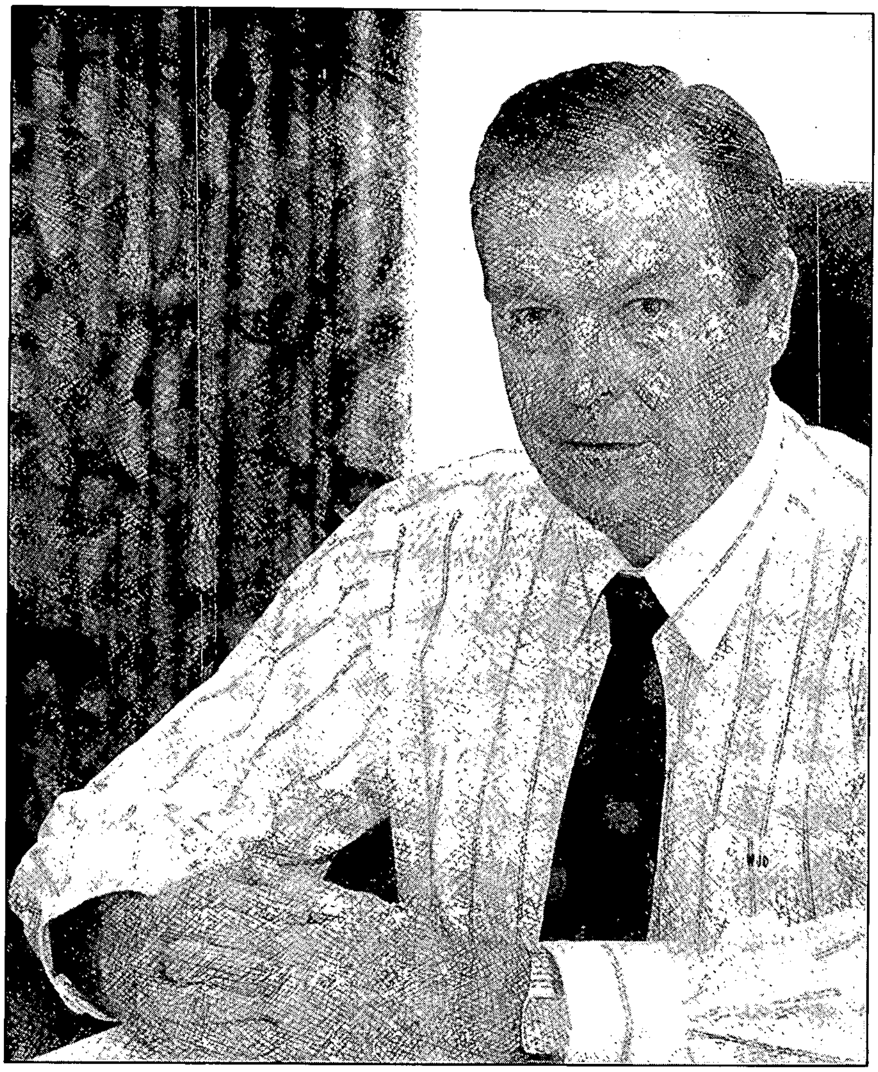
Opinac

Opinac, our Canadian subsidiary, is in the midst of expansion, showing increased potential for growth in earnings, cash flow and oil and natural gas reserves and production.

Opinac operates two distinct business segments. Opinac Exploration Limited, headquartered in Calgary, Alberta, explores for, develops and produces crude oil, natural gas liquids and natural

Aggressive, Responsible Leadership:

"I want Niagara Mohawk to be known throughout the industry as a leader. That will mean being at the forefront of issues involving regulation and the environment. That will mean innovation in our approaches to customer service. And it will mean we are building value for our shareholders."



gas from properties located primarily in Alberta. Canadian Niagara Power Company Limited generates electricity at its Niagara Falls, Ontario hydro plant for its distribution system in Fort Erie and the wholesale market in Ontario and New York.

A steady flow of earnings and cash flow from the electric business has enabled Opinac to explore, develop and acquire significant oil and natural gas reserves and exploratory land holdings. Proven plus probable additional reserves are approximately five million barrels of oil and natural gas liquids, and 290.1 billion cubic feet of natural gas as of the end of the year. This makes Opinac Exploration Limited one of the 25 largest oil and gas companies in Canada.

In 1990, Opinac's average daily production was 1,984 barrels of oil and natural gas liquids, and 69 million cubic feet of natural gas, increases of 35 percent and 57 percent respectively over 1989 production averages.

Electric revenues increased 15 percent in 1990 to $31.8 million (Canadian).

We have approved a plan under which an initial public offering of new common shares of stock would be made in Canada during 1991, depending on market conditions. An underwriter has been selected, and we contemplate filing a preliminary prospectus in 1991. Niagara Mohawk will remain the controlling shareholder following the successful completion of the offering, which is being made to enable Opinac to expand its oil and natural gas activities more rapidly.

A New Niagara Mohawk

This annual report outlines the most significant activities undertaken in 1990, and what is ahead. Yet much more was accomplished than can be detailed here. A small sample includes:

- After several months of negotiation, we agreed to purchase the municipal electrical system in Watertown, allowing us the opportunity to provide service to all customers in that area.
- We completed negotiations for a new three-year labor agreement with the International Brotherhood of Electrical Workers.
- Our research and development efforts include a major project to study the feasibility of generating electricity on a large scale using the latest advances in wind power technology, the first such experiment in the eastern United States.

Much more is yet to come.

Our ability to succeed in achieving our vision hinges, in no small measure, on our ability to forge a new relationship with our regulators – a relationship based on mutual trust and a willingness to work together to balance the interests of customer and shareholder.

We have made a successful start on that task. We have worked with regulators throughout the self-assessment process. We are continuing to negotiate settlement of a number of outstanding regulatory issues, including a possible three-year rate plan.

We have worked hard to open the lines of communication, especially with those who might take an adversary position on any given issue. We will continue to focus on our relationship with regulators in the year ahead.

The vision we have for Niagara Mohawk has been communicated to our employees and our regulators. It is described here for shareholders and the investment community. We intend to extend this communication to our customers and the communities we serve.

All should share in the knowledge of where we are taking Niagara Mohawk, since all will share in the benefits. ■

The Niagara Mohawk Power Corp. 1990 Annual Report is indicative of our commitment to protecting the environment and reducing costs.

The report is printed entirely on recycled paper stock, made in part from post-consumer waste paper gathered, cleaned and bundled by our own Investment Recovery Center. In an agreement with Mohawk Paper Mills of Cohoes, N.Y., we shipped over 17,000 pounds of waste paper from our own operations to be included in the manufacturing process for the product used here.

In addition, we used soybean-based ink for the printing, thus making this recycled report totally recyclable.

The 1990 Annual Report was written, designed and produced by Niagara Mohawk people.

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

The Company is continuing to work with the New York State Public Service Commission (PSC) and other key outside parties to restore its financial integrity which was severely eroded by the 1987 write-off of disallowed Nine Mile Point Nuclear Generating Station Unit No. 2 (Unit 2) construction costs and problems associated with recent nuclear operations of Nine Mile Point Station Units 1 and 2. Several negotiated agreements between the Company, the PSC Staff and other intervenors have had a dominant effect on the Company's financial condition and results of operations over the three-year period ended December 31, 1990. Key provisions of these agreements are highlighted below:

• *1988 Joint Stipulation and Agreement* (1988 Stipulation Agreement) — the Company agreed to, among other things, no increase in base rates for electric service from July 1, 1988 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 was 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 1988 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 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 1988 Stipulation Agreement, resulting in a net reduction in earnings per share of $.15 in 1988.

• *1989 Interim Relief Agreement* — in partial response to a PSC proceeding instituted in September 1988 to investigate the prudence of the Unit 1 extended outage, the Company entered into an agreement under which it suspended collection from ratepayers of $40.7 million in replacement power costs through the fuel adjustment clause mechanism for the first six months of 1989. The degree of uncertainty associated with the ultimate outcome of the PSC's prudence investigation precluded recording of these revenues for financial reporting purposes, which reduced cash flow for that period by $40.7 million and earnings per share during 1989 by approximately $.20.

• *1989 Agreement* — established a framework within which the Company's immediate financial condition was addressed while also providing a process for ultimate resolution of numerous regulatory issues faced by the Company. A key objective of this agreement was to stabilize the Company's financial condition and attempt to maintain its senior securities ratings at investment grade by permitting the Company to defer, for future recovery, certain operating expenses in an attempt to attain specified interest coverage ratio levels through the end of 1990. The parties to the Agreement have agreed to negotiate a multiyear rate plan, including incentive return mechanisms of between 1% and 2% above the authorized return on equity, with the objective of improving the Company's financial condition and the predictability of future rates.

The Company also agreed, among other things, to undertake a comprehensive self-assessment of the efficiency and effectiveness of its organization and management. The Company has submitted to the PSC a work plan, a midcourse milestone report and a progress report of the self-assessment process during the course of 1989 and 1990. A final report, discussing implementation of self-assessment recommendations, is anticipated for May 1991. As discussed below, the Company also agreed to study its gas business, ultimately determining that it should be organized into a strategic business unit. Based upon the benefits identified in this study, the Company announced in 1990 that it would reorganize its other operations into strategic business units, to be in place by July 1, 1991.

• *1990 Unit 2 Cost Settlement* — resolved Unit 2 cost settlement cap, allocation of net contractor litigation proceeds and operating prudence issues and establishes a process for determining future operating and maintenance expense levels. The Company agreed to refund $18 million of replacement power costs (representing a portion of replacement power costs collected from ratepayers during certain outages occurring between April 5, 1988 and January 19, 1990) which was accrued in 1990 results of operations. The establishment of the final construction cost cap resulted in an adjustment to the reserve for disallowed Unit 2 costs provided in 1987, improving pretax earnings by approximately $6 million.

• *1990 Temporary Rate Increase* — on December 19, 1990, the PSC approved a temporary annual rate increase for electric service of $162.8 million or 6.9% and for gas service of $27.2 million or 4.9% which became effective January 1, 1991. These rates are subject to adjustment based upon the results of the permanent rate negotiations. The Company, the PSC Staff and others submitted the 1991 Stipulation to the PSC on February 19, 1991, which establishes, among other things, permanent rates for the year ended June 30, 1991 in an amount equivalent to the level established by the temporary rate increase. A decision from the PSC on the 1991 Stipulation is now anticipated prior to July 1, 1991. For the purpose of establishing temporary rates, certain assumptions were made relative to issues under negotiation pursuant to the 1989 Agreement, including a liability to customers of approximately $130 million for Unit 1 and Unit 2 replacement power costs (including $18 million for Unit 2 replacement power costs established pursuant to the 1990 Unit 2 Cost Settlement) and a reduction in the allowed return on equity from 12.5% to 11.5% in the first rate year to begin returning the funds to customers, as well as rate base recognition of unrecovered regulatory deferrals (principally deferrals associated with targeted interest coverages, nuclear improvement costs and self-assessment costs as permitted in the 1989 Agreement) and recovery of approximately $33 million of these regulatory deferrals in the first rate year. The effect of the deferral recovery and return on equity reduction are approximately offset in the determination of the revenue increase required for the rate year ending June

30, 1991. Based upon management's assessment of the probable outcome of permanent rate negotiations, including the fact that the PSC approved the temporary rate increase, the Company has accrued as a loss in 1990 the anticipated liability to customers for Unit 1 and Unit 2 replacement power costs of $130 million, and has also written off approximately $10 million of deferred capacity charges associated with the Unit 1 outage, resulting in a reduction in earnings per share of $.68.

As indicated above, the Company entered into the 1991 Stipulation with the PSC Staff and others, which was submitted to the PSC on February 19, 1991 and upon which a decision is expected by July 1, 1991. The 1991 Stipulation confirms the level of temporary rate increase that became effective January 1, 1991 as permanent and provides for electric rate increases of 2.9% ($75.4 million) effective July 1, 1991 and 1.9% ($55.7 million) effective July 1, 1992. Gas rates would increase 1.0% ($5.5 million) on July 1, 1992. The agreement acknowledges the Company's intent to file for a rate increase to become effective no earlier than January 1, 1993. The 1991 Stipulation also provides a Unit 1 operation incentive sharing mechanism for the first time. For approximately a four year period beginning October 1, 1990, the actual performance of Unit 1 will be compared to an equivalent capacity factor target of 61.26%. There will be a sharing between customers and shareholders of both replacement power costs incurred (for performance below 61.26%) and costs avoided (for performance above 61.26%). If the actual cumulative capacity factor falls below 40% at the end of the four year period, the Company may petition the PSC for permission to raise the issue of prudence and prove that it ought to be entitled to collect all or a portion of replacement power costs incurred related to performance below 40%. Although the Company has no plans to abandon Unit 1, the 1991 Stipulation establishes that all reasonable and prudently incurred costs associated with abandonment of Unit 1 will be recoverable; however, all parties to the agreement reserve the right to petition the PSC to institute a formal investigation to review the prudence of the Company's decision to retire this Unit.

These agreements do not take into consideration the potential impacts of a number of emerging state and federal 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. These issues include questions of open access to the Company's transmission facilities by other parties, and vice versa, possible "by-pass" of the Company's gas system by large industrial and cogeneration customers, initiatives relating to "incentive regulation" which may change the manner in which rates are set and which may ultimately affect how the consequences of regulation are reflected in the Company's financial statements and the compliance and implementation considerations of the Clean Air Act of 1990 as well as possible stricter state emissions regulation.

The Company's ability to return to financial strength is dependent upon not only its ability to respond appropriately to these challenges and to anticipate other emerging issues, but also approval of the 1991 Stipulation by the PSC and effective management of the costs of its operations within the limitation of the resources available. The successful implementation of the Company's new vision for change and the self-assessment results is intended to enhance management's skills and provide the direction to address these issues.

RESULTS OF OPERATIONS

Earnings per share for 1990, 1989 and 1988 of $.30, $.78 and $1.21, respectively (representing decreases of 62% and 36%, respectively), reflect the financial effects of the regulatory agreements entered into by the Company during 1988, 1989 and 1990 as discussed above, as well as the costs associated with the extended Unit 1 outage, write-off's associated with the Company's investment in NM Uranium, Inc. caused by falling uranium market prices and the costs of new programs that had not, because of changing conditions, been anticipated within certain of the regulatory agreements.

The substantial decrease in earnings per share in 1990 was predominantly the result of several key issues. As discussed below, the Company accrued a loss for Unit 1 and Unit 2 replacement power costs and capacity costs, which reduced earnings by $.68 per share. Pursuant to the 1989 Agreement, the Company deferred expenses in an attempt to achieve specified targeted interest coverage levels, which improved earnings by approximately $.47 per share as compared to 1989; however, such expense deferrals and correspondingly earnings were constrained by the Temporary Rate Agreement. Other factors contributing to the decrease in earnings as compared to 1989 are discussed below and include increases in depreciation, taxes other than income taxes and operating expenses.

The Company accrued the loss of $140 million for Unit 1 and Unit 2 replacement power costs and capacity charges based upon management's assessment of the probable outcome of negotiations of the multiyear rate plan, which are intended to resolve, among other things, the prudence issue related to the extended Unit 1 outage. A key element in management's assessment was the approval by the PSC of the temporary rate agreement discussed above, which included an assumption that the Company would be liable to customers for a refund of $112 million of Unit 1 replacement power costs and $18 million of Unit 2 replacement power costs determined pursuant to the 1990 Unit 2 Cost Settlement Agreement discussed above. The Company also wrote off $10 million of previously deferred capacity costs associated with the Unit 1 outage. See Note 10 of Notes to the Consolidated Financial Statements.

In addition to the negative earnings impact associated with the anticipated outcome of negotiations relating to Unit 1 replacement power cost and the Unit 2 replacement power cost liability established in the 1990 Unit 2 Cost Settlement, the Company estimates that it has absorbed approximately $68 million of Unit 1 replacement power costs during the course of the outage through the Interim Relief Agreement and the sharing provisions of the fuel adjustment clause mechanism. The Company also estimates that it has absorbed approximately $132 million ($28 million in 1988, $69 million in 1989 and $35 million in 1990) of incremental operating and maintenance costs, generally occasioned by the Unit 1 outage, in excess of amounts provided for in the ratesetting process.

Earnings for 1990 and 1989 have also been substantially affected by the 1989 Agreement which addressed the Company's deteriorating 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, as well as establishing target interest coverage levels discussed below. The minimum and target coverages were intended to stabilize the Company's financial condition while negotiations with the PSC Staff and other intervenors were undertaken to address a multiyear rate plan and Unit 1 prudence issues, as well as permitting the Company to conduct a self-assessment program.

The minimum interest coverage level (without AFC) of 1.60 times, which was to exclude extraordinary losses as defined in the 1989 Agreement, was attained in 1989 by the deferral for future recovery of $13.8 million of expenses. There was no deferral of expenses under this coverage provision in 1990; however, the actual interest coverage ratio (without AFC) was 1.35 and was lower than the minimum allowed because of the recording of the anticipated liability for disallowed replacement power costs, which was considered to be an extraordinary loss as defined in the 1989 Agreement. In addition, during the last six months of 1990, minimum cash coverage of 1.60 times (without AFC and non-cash items) was intended to be maintained through a surcharge to customers equivalent to net available transmission and resale gross margin, which amounted to approximately $43 million. The cash surcharge under this provision of the 1989 Agreement served to reduce expense deferrals otherwise permitted to achieve minimum coverages or target coverages (as described below) under the 1989 Agreement. The Company was slightly below the cash coverage target for the year ended December 31, 1990.

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 13, 1989, the Company submitted to the PSC a work plan describing the self-assessment approach, including a schedule for its completion and, on May 1, 1990, a mid-course milestone report was submitted. On November 15, 1990, the Company submitted a report summarizing the progress of the self-assessment to that point, and provided implementation plans addressing the issues identified. A final self-assessment implementation report must be submitted by May 31, 1991.

With the acceptance of the work plan by the PSC on December 29, 1989, the Company was permitted to defer $23 million of expenses for future recovery in an effort to achieve an interest coverage level (without AFC) of 1.75 times in the first six months of 1990. For the twelve months ended June 30, 1990, the Company's interest coverage level without AFC was 1.74 times. The Company was unable to achieve the 1.75 times target due to actual operating results being less favorable than the operating results forecast in the 1989 Agreement which served as a basis for the $23 million deferral.

The mid-course milestone report was approved on July 25, 1990, and under the provisions of the 1989 Agreement, such approval allowed the Company to defer additional expenses for future recovery in an attempt to achieve a targeted interest coverage level (without AFC) of 1.85 times for the last six months of 1990. As provided for in the 1989 Agreement, the calculation of interest coverage would exclude extraordinary items as defined in the 1989 Agreement. During the last six months of 1990 the Company deferred approximately $87 million (before reduction through current recovery of $43 million of cash surcharges) and, excluding the effects of the Unit 1 and Unit 2 replacement power loss accrual, would have achieved a 1.75 times interest coverage. The Company had previously anticipated a deferral of expenses of $120 million (before reduction through cash surcharges) during the second half of 1990 to achieve a 1.85 interest coverage; however, as a result of the increased costs associated with the extension of the Unit 1 outage and power ascension program in 1990 and the course of negotiations of the multiyear rate plan, the Company agreed that an appropriate portion of the temporary rate increase negotiated for the first rate year ending June 30, 1991 would be allocable to the period July 1, 1990 through December 31, 1990. This allocation was then reflected in 1990 results of operations by limiting the expense deferral in the second half of 1990 pursuant to the 1989 Agreement to the allocable portion of the temporary rate increase, or approximately $87 million of the $190 million temporary rate increase approved.

On August 4, 1989, the Company filed an application with the PSC requesting an increase in electric and gas rates for the year ending June 30, 1991. On December 18, 1989, the Company submitted to the PSC revised exhibits updating its August 1989 presentation, seeking an increase in electric and gas rates to produce additional revenues totaling $344.5 million: $317.0 million (14.0%) in electric revenues and $27.5 million (5.1%) in gas revenues. 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 to establish permanent rates to March 1, 1991, although temporary rates were established effective January 1, 1991 subject to adjustment based on the level of permanent rates ultimately established. The Company had previously agreed to an extension of the establishment of permanent rates to April 1, 1991 and recently agreed to a further extension to July 1, 1991. This extension was intended to allow for completion of negotiation of a multiyear rate plan, which as discussed above has resulted in the 1991 Stipulation. The 1989 Agreement also provides for the establishment of an incentive return mechanism which would allow the Company to earn up to 2% per year above the authorized return on equity during the period of the multiyear rate plan. Criteria for earning an initial $30 million of incentive return for the period ending May 31, 1991 have been established. These criteria generally encompass nuclear performance, progress in capturing savings generated in the self-assessment process and customer satisfaction indicators. The terms of the incentive return mechanism for the remaining amounts of incentive return are still subject to negotiation. The Company is unable to predict the amount of incentive return that may be earned or the Company's ability to achieve the goals established pursuant to the incentive mechanism.

The 1991 Stipulation allows costs deferred pursuant to the maintenance of the specified interest coverage targets discussed above or other costs deferred pursuant to the 1989 Agreement, including carrying charges in each case, to be recovered in rates over a period of approximately three years beginning July 1, 1990. The 1990 Temporary Rate Agreement approved by the PSC includes an underlying assumption of amortization and recovery of costs deferred associated with the coverage target deferrals, beginning July 1, 1990.

The Company has been studying the advantages and disadvantages of continuing the operation of Unit 1. Pursuant to the 1989 Agreement, the Company has completed and provided to the PSC and the parties to the 1989 Agreement the study of such operations. Based upon the quantitative and qualitative benefits expected to be derived from continued operation of Unit 1, the Company believes that continued operation of Unit 1 is in the best interest of ratepayers. The PSC Staff issued a response to the Company's study stating that the Company may have overestimated the reliability and value of Unit 1. The Staff differs with the Company as to the break-even capacity factor required for continued economical operation of the Unit. The Staff was also critical of the Company's estimated future costs of capital additions and operations and maintenance. Pursuant to the terms of the 1991 Stipulation, prior to each refueling outage the Company will submit a study in support of either continuing the operation of Unit 1, or reasons for retiring it at that time. The Company is unable to predict what actions may be initiated based upon results of the Unit 1 study or the impact that such results and actions may have on the Company's financial condition or results of operations.

On October 24, 1990, the PSC approved the Company and cotenant companies agreement with the PSC Staff and other parties which resolves the Unit 2 settlement cap, allocation of net contractor litigation proceeds, and operating prudence issues, and establishes a mechanism for determining future operating and maintenance expense levels. The PSC Order has not yet been issued. Based upon the Unit 2 loss recognized in 1987 with the Company's adoption of Statement of Financial Accounting Standards No. 90 and the terms of the 1990 Unit 2 Cost Settlement, the Company reduced its Unit 2 project cost disallowance reserve by approximately $6 million, before Federal income taxes, in 1990. As discussed above, the Company also accrued in 1990 a loss for the refund of replacement power costs associated with Unit 2 operating prudence in the amount of $18 million.

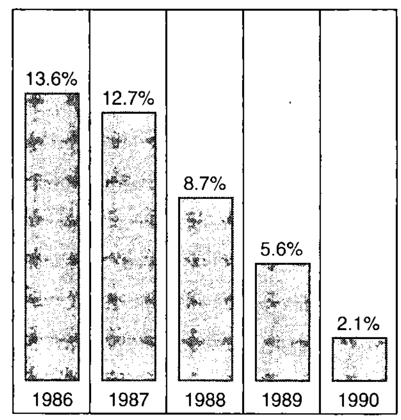
On June 1, 1990, the Company submitted to the PSC, and provided to the parties to the 1989 Agreement, a study of the advantages and disadvantages of separation, sale or other action with respect to the Company's gas business in accordance with the terms of the 1989 Agreement. As a result of this study, the Company announced that it is reorganizing its natural gas business into a separate internal business unit to take better advantage of service and marketing opportunities. The Company cannot predict what further action or actions, if any, the PSC may ultimately take with respect to the study. Based upon the benefits identified in the gas study, the Company announced a reorganization of the remainder of its operations into additional strategic business units effective July 1, 1991 designed to make substantial improvements in the Company's corporate structure and to increase efficiency and responsiveness to customers, as well as to facilitate accountability and responsibility. The Company believes this new structure will enable it to meet the challenges of the 1990's and beyond. Under this plan the Company will form the following strategic business units (SBU's): Electric Customer Service, Electric Supply and Delivery, Nuclear and Gas Customer Service. Corporate Support SBU's will also be created for Finance and Human Resources. By dividing the Company into "natural" businesses that perform specialized functions, each SBU is intended to have control over all key aspects of its business, to enable it to measure its performance and be accountable for overall results against its business plan. The reorganization is expected to be completed by July 1, 1991.

In 1990, the Company's return on common equity fell to 2.1%, reflecting, among other items, the loss associated with the replacement power cost liability accrued for Unit 1 and 2, as compared with 5.6% in 1989 and 8.7% in 1988. Excluding the replacement power cost disallowance, the return on equity would have been 6.9% for 1990, reflecting the effects of operating expenses deferred as permitted in the 1989 Agreement. As a result of expense deferrals utilized in an effort to achieve the target coverage levels established in the 1989 Agreement, non-cash earnings in 1990 represent in excess of 57% of earnings available to Common Stockholders before the accrual of the Unit 1 and Unit 2 replacement power cost liability, as compared to 47% in 1989. The deferred costs are to be recovered over approximately a three-year period generally beginning July 1, 1990, which should serve to decrease the percentage of non-cash earnings in 1991, although other factors such as increasing construction and related AFC will have a countering effect.

The Company anticipates a return on equity of between 9.0% and 10.0% in 1991. The ability to achieve this level of earnings is substantially dependent upon a number of key factors, including the control of expenses, the successful capture of cost savings identified in the self-assessment process and approval by the PSC of the amount of rate increase established by the 1991 Stipulation. Shortfalls in any of these factors would have an adverse impact on the Company's ability to achieve the anticipated return on equity.

The Company has substantially completed the activity value analysis (AVA) portion of the self-assessment process, having involved every department in an evaluation of the effectiveness, efficiency and necessity of its activities. A significant portion of the cost savings identified are subject to negotiation with the IBEW or approval by regulators. The AVA process also identified activities that are not currently being performed but which were considered necessary in the improvement of the Company's reliability and service to customers. The AVA process results have been reflected in the negotiation of the 1991 Stipulation along with any ongoing costs that may be incurred. Start-up costs incurred in implementing AVA recommendations are to be recovered in part by applying the customers' share of Unit 2 contractor litigation proceeds, with the remaining start-up costs to be recovered over a three year period.

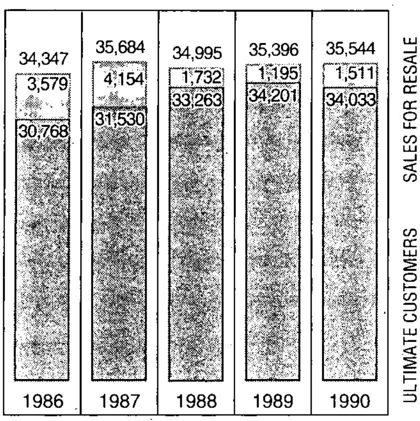
EARNED RATE OF RETURN ON COMMON EQUITY



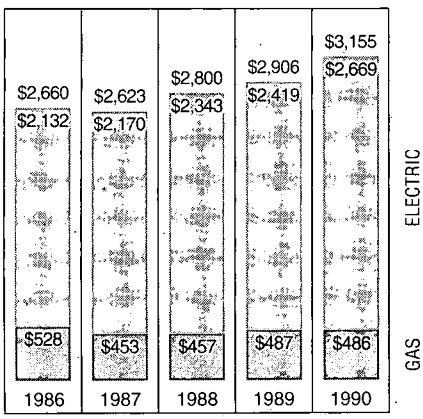
The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1990. It may not be indicative of future operations or earnings particularly in light of the effects of the 1989 Agreement, the Unit 1 extended outage and the nuclear replacement power cost disallowance reflected in 1990. 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 $499.1 million or 23% over the three-year period. This increase results primarily from fuel adjustment clause revenues, 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, the recording of unbilled electric revenues in

ELECTRIC SALES Millions of Kw-hrs.



TOTAL ELECTRIC AND GAS OPERATING REVENUES Millions of dollars



accordance with the 1988 Stipulation Agreement, cash surcharge revenues recognized in 1990 pursuant to the 1989 Agreement discussed above and increased miscellaneous revenues, offset by decreased sales to other electric systems, as indicated in the table below:

Electric revenues	Increase (decrease) from prior year *In millions of dollars* 1990	1989	1988	Total
Sales to ultimate consumers	**$ 49.3**	$ 51.1	$ 82.0	$182.4
Increase in base rates	—	—	12.9	12.9
Cash surcharge revenues	**42.6**	—	—	42.6
Fuel and purchased power cost revenues	**165.0**	61.0	39.8	265.8
Sales to other electric systems	**11.8**	(2.2)	(57.8)	(48.2)
Unbilled electric revenues	**(5.7)**	(39.8)	62.5	17.0
Miscellaneous operating revenues	**(12.3)**	4.8	34.1	26.6
	$250.7	$ 74.9	$173.5	$499.1

Changes in fuel and purchased power cost revenues are generally margin-neutral while sales to other utilities, because of regulatory sharing mechanisms, generally result in low margin contribution to the Company. 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 and through June 30, 1990; since these were used to offset other specified costs, the effect of the amortization of unbilled electric revenues on net operating income was minimal. Remaining amounts of unbilled electric revenue have been deferred for future regulatory recognition and thus have not impacted earnings. The Company has not received authority to accrue unbilled gas revenues. Included in 1988, 1989 and 1990 fuel and purchased power cost revenues are replacement power costs associated with the Unit 1 outage; however, such revenues in 1989 were reduced by $40.7 million of such costs pursuant to the terms of the Interim Relief Agreement. Sales to ultimate consumers in 1990 reflect the billing of a separate factor for demand-side management (DSM) programs providing for the recovery of lost electric margin to the Company for reduced sales occasioned by such programs and a 10% incentive based on the savings to customers of the programs. The PSC authorized the separate DSM billing factor to encourage the Company to undertake DSM programs, which the Company expects will increase in the future as more programs are initiated. The deferral of $11 million of DSM revenues in excess of 1990 DSM program costs is reflected as a reduction in 1990 miscellaneous operating revenues, is included in Other Deferred Credits on the Balance Sheet and is to be amortized to match future DSM program costs.

Electric kilowatt-hour sales were 35.5 billion in 1990, an increase of .4% over 1989 and an increase of 1.6% over 1988. The 1990 increase reflects increased sales to commercial customers and other electric systems partly offset by decreased residential and industrial sales due primarily to the economic recession. Sales in 1989 were affected by a continued decline in sales to other electric systems caused by unfavorable price competition in the wholesale energy market offset by increases in all major customer groups. (See Electric and Gas Statistics — Electric Sales appearing on page 43). The Company expects no growth in sales to ultimate consumers in 1991 as the effects of the recession that began in 1990 have put downward pressure on industrial sales, not quite offset by growth in commercial and residential sales. The 1991 Stipulation includes the institution of an electric revenue adjustment mechanism (ERAM) that would require the Company to reconcile actual to forecast electric public sales margin. An ERAM would provide stability as to gross margin (generally revenues less fuel costs). Depending on the level of actual future sales, a liability to customers would be created if sales exceeded the forecast, and an asset would be recorded for a sales shortfall, therefore, generally holding recorded margin to the level forecast in establishing rates. The 1991 Stipulation, which is subject to PSC approval, would extend the ERAM through June 30, 1993.

Details of the changes in electric revenues and kilowatt-hour sales by customer group are highlighted in the table below:

Class of service	1990 % of Electric Revenues	% Increase (decrease) from prior year 1990 Revenues	1990 Sales	1989 Revenues	1989 Sales	1988 Revenues	1988 Sales
Residential	**34.4%**	**8.8%**	**(0.5)%**	4.6%	2.6%	9.0%	4.6%
Commercial	**36.7**	**12.0**	**1.7**	5.6	2.2	5.7	4.3
Industrial	**20.3**	**11.8**	**(2.5)**	6.1	3.7	5.2	7.5
Municipal service	**1.7**	**6.0**	**(0.9)**	2.6	(3.8)	1.5	0.8
Total to ultimate consumers	**93.1**	**10.6**	**(0.5)**	5.3	2.8	6.7	5.5
Other electric systems	**2.6**	**20.3**	**26.4**	(3.6)	(31.0)	(49.0)	(58.3)
Miscellaneous	**4.3**	**0.1**	**—**	(23.2)	—	179.2	—
Total	**100.0%**	**10.4%**	**0.4%**	3.2%	1.1%	8.0%	(1.9)%

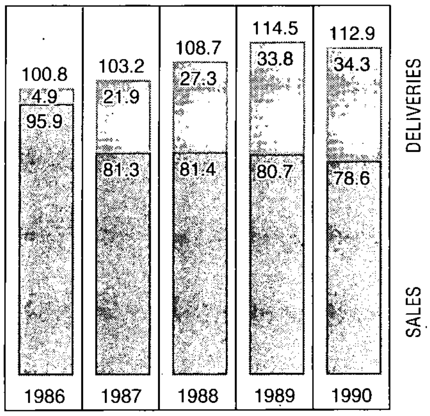
On March 13, 1987, the PSC approved a 4.0% electric rate increase to provide the Company additional annual revenues of $74,898,000 based on (i) forecast sales for the twelve months ended March 31, 1988, (ii) a 13.0% return on equity, and (iii) the inclusion of $1.625 billion of construction work-in-progress (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 under the Tax Reform Act of 1986 and a reduction to 13.0% from 14.0% return on equity requested by the Company. This represents the last permanent electric rate increase approved for 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 (1988 Stipulation Agreement) 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 was extended to December 31, 1990. Temporary rates have been approved by the PSC effective January 1, 1991 pursuant to the 1989 Agreement, and would be subject to adjustment if the level of permanent rates for the rate year ended June 30, 1991 were established at a level different from the temporary rates. The Company, PSC Staff and others submitted the 1991 Stipulation on February 19, 1991, which provides for, among other things, the establishment of permanent rates for this period at the same level as the temporary rates. The 1991 Stipulation is subject to approval by the PSC.

Gas revenues increased $32.2 million or 7.1% over the three-year period. As shown by the table below, this increase is primarily attributable to increased purchased gas adjustment clause revenues and increased revenues from transportation of gas for others offset slightly by decreased miscellaneous revenues. Although rates for transported gas yield lower margins than gas sold directly by the Company, decreases in gas revenues caused by the migration of customers to the transported gas classification have not had a significant impact on earnings. Also, changes in purchased gas adjustment clause revenues are generally margin-neutral.

Gas revenues	Increase (decrease) from prior year *In millions of dollars* 1990	1989	1988	Total
Purchased gas adjustment clause revenues	**$5.3**	$23.5	$(6.2)	$22.6
Sales to ultimate consumers and other sales	**(7.4)**	4.2	3.8	0.6
Transportation of customer-owned gas	**2.2**	6.0	2.3	10.5
Miscellaneous operating revenues	**(2.1)**	(3.0)	3.6	(1.5)
	$(2.0)	$30.7	$ 3.5	$32.2

GAS SALES Millions of dekatherms



Gas sales, excluding transportation of customer-owned gas, were 78.6 million dekatherms in 1990, a 2.6% decrease from 1989 and 3.5% decrease from 1988 (See Electric and Gas Statistics — Gas Sales appearing on page 43). The decrease for 1990 includes a 5.6% decrease in sales in the residential class and a 1.4% decrease in sales in the commercial class reflecting milder weather factors, offset by a 57.6% increase in sales in the industrial class as a result of increasing oil prices due to the current Persian Gulf situation. Conversely, the changes in the residential and industrial sales in 1989 from 1988 reflect more severe weather factors, unfavorable competition with oil prices and the ability of large customers to purchase gas directly from producers. In 1990, the Company transported 34.3 million dekatherms for customers purchasing gas directly from producers and expects a continued increase in such transportation activities. To the extent the increases in transportation revenues are due to existing customers electing to purchase gas directly from suppliers, there is a corresponding reduction in gas revenues. The Company has forecast an increase in total gas deliveries in 1991 in excess of 10% principally in the transportation category, although public sales are expected to increase almost 5%. Factors impacting on these increases include the effects of the recession that began in 1990, the relative price differences between oil and gas and the relative availability of each fuel. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

	1990 % of Gas	% Increase (decrease) from prior year					
		1990		1989		1988	
Class of service	Revenues	Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	**63.3%**	**(3.2)%**	**(5.6)%**	9.9%	3.6%	3.2%	6.3%
Commercial	**26.5**	**2.0**	**(1.4)**	5.0	(3.3)	(1.0)	1.8
Industrial	**4.0**	**57.0**	**57.6**	(35.2)	(38.9)	(36.1)	(41.0)
Total to ultimate consumers	**93.8**	**(0.2)**	**(2.2)**	6.5	(0.8)	(0.7)	0.6
Other gas systems	**1.6**	**(14.7)**	**(14.7)**	(1.0)	(6.4)	6.4	(13.8)
Transporation of customer-owned gas	**4.5**	**11.4**	**1.4**	43.3	24.0	19.8	24.6
Miscellaneous	**0.1**	**(84.0)**	—	(54.5)	—	189.9	—
Total	**100.0%**	**(0.4)%**	**(1.4)%**	6.7%	5.3%	0.8%	5.3%

In January 1988, the PSC approved a gas rate settlement proposed by the Company and interested parties which maintained 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. Temporary rates have been approved by the PSC effective January 1, 1991, and would be subject to adjustment if the level of permanent rates for the year ended June 30, 1991 were established at a level different from those in the Temporary Rate Agreement. The Company, PSC Staff and others submitted the 1991 Stipulation on February 19, 1991 which provides for, among other things, the establishment of permanent rates for this period at the same level as the temporary rates. The 1991 Stipulation is subject to approval by the PSC. The last permanent gas rate increase was approved in 1985.

In 1990, electric fuel and purchased power costs increased to $878 million from $771 million in 1989 and $704 million in 1988. The increase in 1990 is the result of a $7.6 million increase in fuel and purchased power costs incurred combined with a $99.2 million net increase in costs deferred and recovered through the operation of the fuel adjustment clause. While kilowatt-hour generation increased 5.8% principally due to the return to service of Unit 1, fuel costs incurred increased 9.1% as a result of shift in fuel mix and increased oil prices. Kilowatt-hour purchases and costs incurred decreased 8.1% and 7.5%, respectively, as a result of the return to service of Unit 1. 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 1989 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 43). The Company has increased its fuel inventory quantities as of December 31, 1990 to protect against potential world supply disruptions resulting from events in the Persian Gulf.

The total cost of gas purchased decreased 1.0% in 1990, after having increased 8.9% in 1989, and decreased 1.1% in 1988. The decrease for 1990 is the result of a 9.2% decrease in dekatherms purchased to meet customer demand at slightly lower rates charged by the Company's suppliers, offset by an increase of $29.1 million in purchased gas costs and certain other items recognized and recovered through the purchase gas adjustment clause. 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. During the three year period, the Company purchased the maximum allowable portion of its gas supply requirements on the spot market, as permitted under its contract with its principal supplier, to take advantage of lower spot market prices. The Company's net cost per dekatherm purchased increased to $3.70 in 1990 from $3.39 in 1989 and $3.19 in 1988.

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 $14.0, $13.3, and $21.4 million for each of the three years ended December 31, 1990, 1989 and 1988, respectively. Absorbed costs in 1988 exceeded $15 million due to the timing of rate years and of variances from fuel targets. In 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. This proceeding is continuing and the Company is unable to predict the outcome. The 1991 Stipulation includes a Unit 1 operation incentive sharing mechanism which may have an impact on the fuel adjustment clause mechanism.

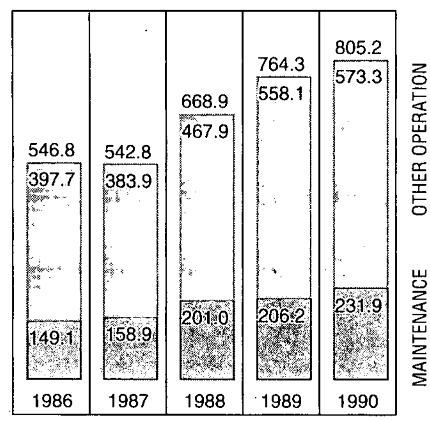
Other operation expense increased $15.2 million or 2.7% in 1990 as compared to increases of 19.3% in 1989 and 21.9% in 1988. The 1990 increase is net of the deferral of $53.0 million of expenses pursuant to the target interest coverage ratio provisions of the 1989 Agreement and $4.7 million of nuclear improvement program costs included in Other Deferred Debits on the Balance Sheet. The interest coverage ratio deferral has been reduced by $42.6 million of cash surcharge revenues permitted by the 1989 Agreement and $14.8 million of amortization of the interest coverage ratio deferral through December 31, 1990 pursuant to the 1990 Temporary Rate Agreement. The 1989 increase in other operation expense is also net of expense deferrals of $13.8 million related to the interest coverage ratio deferral and $7.1 million of nuclear improvement program cost deferrals. Without the deferrals in the respective periods, other operation expense would have increased 9.0% and 23.7% in 1990 and 1989, respectively. Contributing to the 1990 increase were increased labor costs due to the negotiated wage increases effective June 1, 1990 for represented employees and regular merit increases for salaried employees, rising health care costs which escalated nearly 20% over 1989 levels and increased costs related to demand-side management programs which were fully implemented in 1990. As noted in the discussion of electric revenues above, demand-side management program costs are recovered by a specific rate included on customer bills and are matched accordingly. The Company also experienced increased administrative costs associated with the sale of its Accounts Receivable, having increased the amount sold to $200 million in 1990. Offsetting these increases were lower nuclear operating expenses, reflecting the completion of the 31 month Unit 1 outage and its return to full service in October 1990, with increased Unit 2 refueling outage and operating costs partially offsetting the Unit 1 reduction. The 1989 increase in operation expense was due to the increased outage costs at Unit 1 and increased labor costs, as well as reflecting a full year's operation of Unit 2, which, for ratemaking purposes, was considered to have started commercial operation in April 1988. Also reflected in other operation expense is the effect of the amortization of a previously deferred pension settlement gain over an eighteen year period, pursuant to the 1989 Agreement, which amounted to $4.6 million in 1990 and $3.4 million in 1989.

Maintenance expense increased 12.5% in 1990, 2.6% in 1989 and 26.4% in 1988, primarily due to increased levels of maintenance at production steam plants, Unit 2 and on the Company's electric distribution system. The substantial increase in 1988 resulted 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.

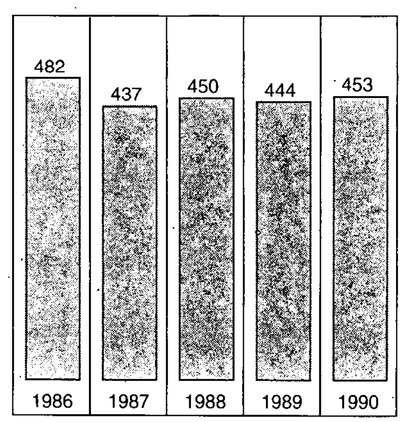
Depreciation and amortization expense for 1990 increased 4.7% over 1989 due to normal plant growth. The decrease of 5.0% in 1989 was the result of the inclusion in 1988 of the amortization of costs associated with the discontinued Lake Erie Generating Station Project in accordance with the 1988 Stipulation Agreement (See Note 2 of Notes to the Consolidated Financial Statements) offset by Unit 2 becoming commercial.

Net Federal and foreign income taxes for 1990 and 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 began being charged to operations since July 1, 1988 and higher revenue taxes as a result of the imposition of a 15% New York State surtax in 1990 and higher revenues.

MAINTENANCE AND OTHER OPERATION EXPENSE Millions of dollars



TOTAL TAXES INCLUDING INCOME TAXES Millions of dollars



Other income and deductions, excluding Federal income taxes, decreased $2.9 million from 1989, in part, attributable to a decline in subsidiary earnings. The increase in 1989 from 1988 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 1988 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 $10.4 million in 1990, primarily the result of the issuance of $300 million in First Mortgage Bonds in both 1989 and 1990 less the impact of debt retirements. Dividends on preferred stock decreased $2.9 million in 1990 as a result of net reductions in amounts of stock outstanding. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 9.87% and 7.56%, respectively, in 1990, from 9.18% and 7.71%, respectively, in 1989.

Effects of Changing Prices. The rate of inflation was 5.4% in 1990. 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.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Financial Position. The Company's capital structure at December 31, 1990 was 57.4% long-term debt, 9.1% preferred stock and 33.5% common equity as compared to 57.2%, 9.6% and 33.2%, respectively, at December 31, 1989. 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 had incurred, and the required reliance on debt financing, through December 31, 1990 the Company was unable to improve its capital structure. The Company has had to rely strictly on debt financing as a result of its inability to prudently access equity markets, reflecting its tenuous financial condition. Book value of the common stock was $14.37 per share at December 31, 1990 as compared to $14.07 per share at December 31, 1989; the increase is primarily attributable to the omission of common stock dividends beginning with the third quarter 1989.

The ratio of earnings to fixed charges for 1990 was 1.41 times which reflects the effects of the loss accrued for Unit 1 and Unit 2 replacement power costs as discussed above in Results of Operations. This is compared to the 1989 ratio of 1.71 times and the 1988 ratio of 2.10 times. Excluding the effect of the loss accrual, the 1990 ratio would have been 1.82 times. The 1990 and 1989 ratios of earnings to fixed charges reflect 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 1990 and 1989 as discussed at greater length under Results of Operations above.

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 issues associated with a number of ongoing regulatory proceedings, determined to omit the third quarter 1989 common stock dividend. Resumption of payment of the common stock dividend will depend on, among other things, the resolution of issues affecting the long-range financial condition of the Company, principally the negotiation or litigation, and subsequent PSC approval, of a multiyear rate plan. (See also: Market Price of Common Stock and Related Stockholder Matters).

Construction and Other Capital Requirements. The Company's overall capital 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 since 1987 have been relatively stable. Annual expenditures for the years 1988-1990 for construction and nuclear fuel, including related AFC and overheads capitalized, were $366.1 million, $413.5 million and $431.6 million, respectively.

The 1991 estimate for construction additions, overheads capitalized and nuclear fuel, excluding AFC, is approximately $544 million, of which approximately 77% 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 $148 million (expected to be refinanced from external sources) to the Company's capital requirements, for a total of $692 million. Current estimates of total capital requirements for the years 1992-1995 are $775 million, $650 million, $899 million and $670 million, respectively. The estimate of construction additions, included in capital requirements for the period 1992 to 1995 will be periodically reviewed by management, taking into consideration future levels of rate relief and internal sources of funds, as well as the effect capital requirements have on the level of external financing. The substantial increase in the Company's estimated capital requirements for the years 1992 through 1995 from amounts previously disclosed is caused by a number of emerging issues. A bid by the Company to extend the life of one of its Huntley coal-fired generating units was selected as one of the sources of capacity sought in the Company's first competitive bidding program. The cost of refurbishment, including the installation of scrubbers at this unit as well as at another Huntley unit to meet the emission limits of the federal Clean Air Act Amendments of 1990 (the "Clean Air Act"), is expected to approximate $174 million (excluding AFC and overhead costs), to be incurred through 1994. Previous estimates of capital requirements did not include expenditures for this project. The forecast construction expenditures for 1992 through 1995 does not include other potential costs that may arise from compliance with the federal Clean Air Act. The provisions of the Clean Air Act are expected to have an impact on the Company's fossil generation plants by no later than 2000, with certain earlier compliance requirements for its coal plants. The Company currently believes that compliance with the emission restrictions can be met with currently available control technology and fuel switching alternatives; however, until specific regulations implementing the Clean Air Act are issued, the Company can provide no assurance in this regard. Based upon this preliminary assessment as to methods of compliance, the Company estimates that capital costs (including the scrubbers at Huntley discussed above) could reach $150 to $200 million through 2000 and that rates may rise 2 to 3% to cover increased fuel and operating and maintenance costs and to recover capital costs incurred. The Company believes that all capital costs, as well as incremental operating and maintenance costs and fuel costs, will be recoverable from its ratepayers.

Management recently approved a program to reinforce sections of the Company's electric transmission network that are approaching the end of their useful lives. The anticipated cost of the reinforcement effort is approximately $58 million within the forecast period. The reinforcement effort is expected to continue beyond 1995.

Also considered within the Company's capital requirements are plans to construct in 1991, a $26 million gas pipeline across the St. Lawrence River to import Canadian gas supplies. The primary objective of the pipeline is to improve the strategic diversity of the Company's gas supply.

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.

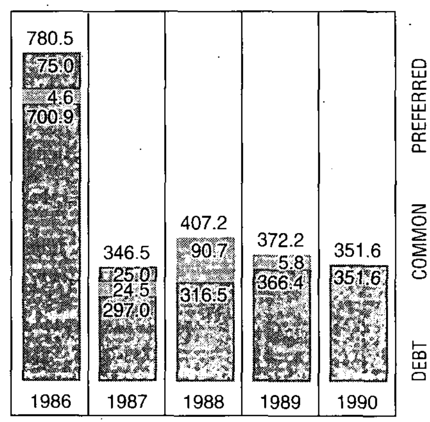
During 1990, the Company raised approximately $351.6 million through external sources, consisting of $300 million of debt and a net increase of $51.6 million of short-term debt and intermediate term bank revolving credit obligations. The Company also completed $10.0 million of capital lease financing. These amounts include external financing done directly by the Company's subsidiaries, which amounted to $15 million in 1990.

Also during 1990, the Company made unscheduled redemptions of two First Mortgage Bond issues: a $50 million 11% Series due 1993 on August 1, and a $37.336 million 12.95% Series due 2000 on December 31. Capital needs have also been affected by the extended Unit 1 outage, the suspension of the common stock dividend and collection of a cash surcharge in 1990 as permitted under the 1989 Agreement.

The Company expects external financing of approximately $250 to $325 million for 1991, depending upon, among other things, the possible resumption and level of the common stock dividend in 1991 as well as approval by the PSC of the 1991 Stipulation. External financing is projected to consist mainly of long-term debt. 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. External financing plans for 1992 to 1995 are subject to periodic revision as underlying assumptions are changed to reflect new developments; however, the Company currently anticipates a range of external financing, in the aggregate of approximately $1.1 billion. The aggregate level of financing during this four year period will reflect, among other things, the nature, timeliness and adequacy of rate relief including PSC approval of the 1991 Stipulation which is effective through December 31, 1992, uncertain demand due to economic conditions, capital expenditures relating to distribution and transmission load reliability projects and gas pipeline expansion. Start-up and other costs associated with the implementation of self-assessment recommendations, compliance with federal and state environmental quality standards, the effects of rate regulation and various regulatory initiatives, 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 will also impact the amount and type of future external financing.

Provisions have been made within the external financing forecast to address the investigation and remediation of both Company owned and Company-associated hazardous waste sites. Such amounts, which approximate $310 million through 2000 and include the Company's estimated 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 based on Environmental Protection Agency (EPA) generic projections of costs to be incurred for a "typical" remediation effort. The estimate of total costs ex-

ANNUAL EXTERNAL FINANCING BY TYPE Millions of dollars



cludes possible recoveries from other Potentially Responsible Parties (PRP's) associated with Company-owned sites, which the Company currently estimates at approximately $29 million, excluding legal costs that may be incurred in pursuing participation by other PRP's. 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 extent of remediation and ongoing monitoring required, as well as the determination of the Company's share of cost responsibility for such remediation and monitoring. The Company believes that costs incurred in the investigation and restoration process should generally be recoverable in the ratesetting process. (See Note 11 of Notes to Consolidated Financial Statements under "Environmental Issues.") The Company and PSC Staff have been discussing the implementation of a recovery mechanism for costs incurred for site investigation and remediation, which would specifically allocate revenues collected to recover such expenditures. This proposal has been included within the 1991 Stipulation for the establishment of permanent rates.

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. 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 $344 million and $446 million in future dollars. The temporary rate agreement approved by the PSC and which became effective January 1, 1991, specifically includes an allowance for nuclear decommissioning of Units 1 and 2 that is sufficient to meet the Company's determined minimum requirement. Pursuant to the terms of the temporary agreement, such allowances will be accepted in future years unless and until the cost of decommissioning changes. The level of allowances was confirmed in the 1991 Stipulation, subject to PSC approval. The Company filed a decommissioning report for each Unit with the NRC in July 1990.

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, 1990, under the applicable earnings test set forth in the indenture, the Company would be permitted to issue up to $233 million of First Mortgage Bonds assuming a 10% 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 $217 million of First Mortgage Bonds. In addition, the Company has the ability to issue approximately $1,185 million of First Mortgage Bonds at December 31, 1990 on the basis of retired bonds without regard to the earnings or Additional Property tests. $200 million of Preference Stock is currently authorized for sale. 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.

The Company's securities ratings at December 31, 1990 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

Ratings are subject to revision or withdrawal at any time and each rating should be evaluated independent of any other rating. The lowest rating considered to be investment grade is Baa3 (baa3 for preferred stock) for Moody's Investors Services and BBB- for the other rating agencies.

Moody's has recently identified the Company for a possible upgrade in its credit ratings, prompted by the PSC's approval of temporary rates effective January 1, 1991. However, an adverse outcome as to levels of permanent rate relief could lead to increased levels of debt financing and could result in a reduction in the Company's credit ratings. 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 put further pressure on credit ratings. The Company's cost of financing and access to markets could also be negatively impacted by events outside of its control, such as a possible tightening of credit markets caused by the savings and loan collapse and money center bank financial concerns.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a continuing basis. This approach generally results in the Company showing a working capital deficit; however, the Company has sufficient borrowing capacity to fund such a deficit as necessary. Bank credit arrangements which, at December 31, 1990, totaled $617 million, (including $180 million in commitment under a Revolving Credit Agreement, $100 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement of Oswego Facilities Trust, $56 million in one-year commitments under Credit Agreements, $181 million in lines of credit of which $60 million is related to a subsidiary, 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 1990 and 1989 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, 1991, equates to approximately $610 million and against which the Company had outstanding unsecured debt of approximately $310 million.

Consolidated Balance Sheets

At December 31,	1990	1989
	In thousands of dollars	
ASSETS		
Utility plant *(Note 1):*		
Electric plant	**$6,999,244**	$6,726,656
Nuclear fuel *(Note 3)*	**398,407**	410,207
Gas plant	**690,485**	650,175
Common plant	**171,623**	149,554
Construction work in progress	**442,982**	387,520
Total utility plant	**8,702,741**	8,324,112
Less accumulated depreciation and amortization	**2,484,124**	2,283,307
Net utility plant	**6,218,617**	6,040,805
Other property and investments	**268,149**	215,836
Current assets:		
Cash, including temporary cash investments of $3,455 and $26,475, respectively	**63,571**	47,912
Accounts receivable (less allowance for doubtful accounts of $3,600) *(Note 11)*	**150,296**	205,260
Unbilled electric revenues *(Note 1)*	**131,100**	131,100
Materials and supplies, at average cost:		
Coal and oil for production of electricity	**109,562**	69,071
Other	**138,110**	113,550
Prepayments:		
Taxes	**9,633**	44,814
Pension expense *(Note 8)*	**53,693**	76,529
Other	**36,766**	25,121
	692,731	713,357
Deferred debits:		
Unamortized debt expense	**112,285**	121,515
Deferred recoverable energy costs	**52,546**	93,846
Deferred finance charges *(Note 1)*	**239,880**	239,880
Deferred operating expenses	**67,919**	13,980
Other	**118,187**	123,253
	590,817	592,474
	$7,770,314	$7,562,472
CAPITALIZATION AND LIABILITIES		
Capitalization *(Note 6):*		
Common stockholders' equity:		
Common stock, issued 136,099,654 shares	**$ 136,100**	$ 136,100
Capital stock premium and expense	**1,649,294**	1,649,285
Retained earnings	**169,724**	129,146
	1,955,118	1,914,531
Non-redeemable preferred stock	**290,000**	290,000
Redeemable preferred stock	**241,550**	267,530
Long-term debt	**3,313,286**	3,249,328
Total capitalization	**5,799,954**	5,721,389
Current liabilities:		
Short-term debt *(Note 4)*	**65,912**	35,671
Long-term debt due within one year	**216,251**	196,508
Sinking fund requirements on redeemable preferred stock	**17,980**	17,980
Accounts payable	**247,548**	291,658
Payable on outstanding bank checks	**34,101**	47,810
Customers' deposits	**10,555**	10,088
Accrued taxes	**32,511**	10,379
Accrued interest	**79,824**	81,533
Accrued vacation pay	**33,431**	30,379
Other	**3,352**	28,054
	741,465	750,060
Deferred credits:		
Accumulated deferred Federal income taxes	**631,354**	656,235
Deferred finance charges *(Note 1)*	**239,880**	239,880
Unbilled electric revenues *(Note 1)*	**28,868**	45,899
Deferred pension settlement gain *(Note 8)*	**74,707**	79,304
Accrued refunds to customers for replacement power cost disallowance *(Note 10)*	**115,168**	—
Other	**138,918**	69,705
	1,228,895	1,091,023
Commitments and contingencies *(Notes 3, 10 and 11)*	**—**	—
	$7,770,314	$7,562,472

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	**1990**	1989	1988
	In thousands of dollars		
Operating revenues:			
Electric	**$2,669,308**	$2,418,662	$2,343,732
Gas	**485,411**	487,381	456,721
	3,154,719	2,906,043	2,800,453
Operating expenses:			
Operation:			
Fuel for electric generation	**460,485**	415,362	360,373
Electricity purchased	**417,429**	355,706	343,511
Gas purchased	**285,868**	288,734	265,033
Other operation expenses	**573,265**	558,073	467,873
Maintenance	**231,895**	206,214	200,969
Depreciation and amortization *(Note 2)*	**220,857**	210,873	222,022
Federal and foreign income taxes *(Note 9)*	**121,114**	105,103	134,451
Other taxes	**391,745**	354,019	329,869
	2,702,658	2,494,084	2,324,101
Operating income	**452,061**	411,959	476,352
Other income and deductions:			
Allowance for other funds used during construction *(Note 1)*	**10,674**	10,085	5,149
Federal income taxes	**12,395**	14,770	13,587
Nuclear replacement power cost disallowance	**(139,974)**	—	—
Related income tax of cost disallowance	**47,600**	—	—
Other items (net)	**8,251**	11,734	(19,945)
	(61,054)	36,589	(1,209)
Income before interest charges	**391,007**	448,548	475,143
Interest charges:			
Interest on long-term debt	**311,728**	296,232	264,866
Other interest	**7,141**	10,824	7,336
Allowance for borrowed funds used during construction	**(10,740)**	(9,291)	(5,873)
	308,129	297,765	266,329
Net income	**82,878**	150,783	208,814
Dividends on preferred stock	**42,300**	45,182	49,157
Balance available for common stock	**40,578**	105,601	159,657
Dividends on common stock	—	81,623	158,228
	40,578	23,978	1,429
Retained earnings at beginning of year	**129,146**	105,168	103,739
Retained earnings at end of year	**$ 169,724**	$ 129,146	$ 105,168
Average number of shares of common stock outstanding *(in thousands)*	**136,100**	136,052	131,853
Balance available per average share of common stock	**$ .30**	$ .78	$ 1.21
Dividends paid per share	**$ .00**	$ .60	$ 1.20

( ) Denotes deduction

Consolidated Statements of Cash Flows
Increase (Decrease) in Cash

For the year ended December 31,	1990	1989	1988
	In thousands of dollars		
Cash flows from operating activities:			
Net income	**$ 82,878**	$150,783	$208,814
Adjustments to reconcile net income to net cash provided by operating activities:			
Nuclear replacement power cost disallowance	**115,168**	—	—
Depreciation and amortization	**220,857**	210,873	222,022
Amortization of nuclear fuel	**27,878**	20,767	16,362
Loss on investment in NM Uranium, Inc.	**15,000**	14,500	7,500
Provisions for deferred Federal income taxes	**(24,881)**	85,733	88,761
Allowance for other funds used during construction	**(10,674)**	(10,085)	(5,149)
Deferred recoverable energy costs	**41,300**	(61,607)	(23,803)
Gain on sale of investments	**(6,614)**	(7,660)	(1,477)
Unbilled electric revenues	**(17,031)**	(22,735)	(62,466)
Decrease in mandated refunds to customers	—	(5,613)	(30,554)
Deferred operating expenses	**(53,939)**	(13,980)	—
Decrease in net accounts receivable	**54,964**	23,654	76,114
Increase in materials and supplies	**(39,031)**	(34,973)	(3,000)
Increase (decrease) in accounts payable and accrued expenses	**(36,122)**	63,315	46,727
Increase (decrease) in accrued interest and taxes	**20,423**	3,938	(2,198)
Changes in other assets and liabilities	**111,135**	3,954	(28,366)
Net cash provided by operating activities	**501,311**	420,864	509,287
Cash flows from investing activities:			
Construction additions	**(418,328)**	(387,178)	(349,823)
Nuclear fuel	**(3,200)**	(20,021)	(3,759)
Less: Allowance for other funds used during construction	**10,674**	10,085	5,149
Acquisition of utility plant	**(410,854)**	(397,114)	(348,433)
Increase in materials and supplies	**(26,020)**	(23,316)	(2,133)
Increase (decrease) in accounts payable and accrued expenses	**(9,030)**	15,829	12,877
Payments under Cotenant Agreement	—	—	(171,100)
Increase in other investments	**(52,255)**	(52,162)	(39,723)
Other	**(16,777)**	(6,426)	9,197
Net cash used in investing activities	**(514,936)**	(463,189)	(539,315)
Cash flows from financing activities:			
Proceeds from sale of common stock	—	5,841	90,683
Sale of mortgage bonds	**300,000**	300,000	200,000
Issuance of other long-term debt	—	100,000	69,800
Redemption of preferred stock	**(25,980)**	(27,980)	(56,980)
Reductions of long-term debt	**(240,110)**	(98,652)	(137,193)
Net change in short-term debt and revolving credit agreements	**51,591**	(33,629)	46,736
Dividends paid	**(42,300)**	(126,805)	(207,385)
Change in dividends payable	**(9,148)**	(41,175)	30,217
Other	**(4,769)**	(6,390)	(16,614)
Net cash provided by financing activities	**29,284**	71,210	19,264
Net increase (decrease) in cash	**15,659**	28,885	(10,764)
Cash at beginning of year	**47,912**	19,027	29,791
Cash at end of year	**$ 63,571**	$ 47,912	$ 19,027
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	**$329,390**	$308,168	$282,555
Income taxes	**19,358**	3,577	42,348
Supplemental schedule of noncash investing and financing activities:			
Capital lease obligations incurred	**$ 10,051**	$ 6,293	$ 12,560

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.

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 at December 31, 1990 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 balances in the deferred accounts, each amounting to $239.9 million at December 31, 1990 and 1989, 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.

The Company, the PSC Staff and others submitted an agreement (the 1991 Stipulation) to the PSC on February 19, 1991 establishing rates through December 31, 1991. There was no resolution of the disposition of the deferred finance charges proposed.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory 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 a nuclear 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 (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 1988 Stipulation Agreement. Approximately $17.0 million, $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, 1990, 1989 and 1988, respectively, as specified within the 1988 Stipulation Agreement and the remainder is included in Deferred Credits. Remaining unrecognized amounts may be used to reduce future revenue requirements. The amount of the remaining deferred credit balance fluctuates as the amount of accrued electric unbilled revenues is recalculated each year end.

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. The Company absorbed $14.0, $13.3 and $21.4 million for each of the years ended December 31, 1990, 1989 and 1988, respectively.

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.

Since it is the Company's intention to reinvest the undistributed earnings of its foreign subsidiaries, no provision is made for federal income taxes on these earnings. At December 31, 1990, the cumulative amount of undistributed earnings of foreign subsidiaries on which the Company has not provided deferred taxes was approximately $110 million.

The Financial Accounting Standards Board (FASB) has issued Statements of Financial Accounting Standards No. 96, No. 100 and No. 103 (SFAS No. 96, No. 100 and No. 103) "Accounting for Income Taxes" which will require the adoption of the provisions of SFAS No. 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. The FASB is currently considering issuance of an Exposure Draft addressing a delay in the effective date of SFAS No. 96 as well as amendments to the measurement of deferred tax assets. The FASB is also considering a requirement for public utilities to adjust any remaining plant-in-service balances that reflect net-of-tax AFC to a pre-tax basis and record the appropriate amount of deferred taxes. Such an adjustment would increase plant-in-service and deferred tax liability on the balance sheet.

Any impact of the pronouncement and the proposed amendments 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 results of operations. However, the adoption of the pronouncements may have a significant impact on the Company's balance sheet, with the recording of deferred tax liabilities and regulatory assets associated with previously flowed-through tax benefits.

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 6).

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.

Reclassifications: Certain amounts have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1990 presentation.

NOTE 2. Depreciation and Amortization

The total provision for depreciation and amortization, including amounts charged to clearing accounts, was $222,055,000 for 1990, $212,067,000 for 1989, and $223,198,000 for 1988. The 1988 provision includes approximately $39,813,000 resulting from the amortization of costs associated with the discontinued Lake Erie Generating Station Project in accordance with the 1988 Stipulation Agreement which permitted the Company to offset such amortization with the recognition in electric operating revenues of an equivalent amount of unbilled electric revenues. The percentage relationship between the total provision for depreciation and average depreciable property was 2.9% for 1990 and 1989, and 2.7% in 1988. 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.

Also included within the annual provision for depreciation and amortization for each of the years ended December 31, 1990, 1989 and 1988 was approximately $4.8, $4.5 and $4.2 million, respectively, for decommissioning Unit 1 and the Company's share of the cost of decommissioning Unit 2. (See Note 10. "Nuclear Decommissioning").

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 approximately $50 million and $35 million at December 31, 1990 and 1989, respectively, totaled $15.5 million at December 31, 1990 and $30.1 million at December 31, 1989. The net investment balance represents the estimated recoverable value of the remaining uranium inventory. Approximately 955,000 pounds of NMU uranium remain to be transferred, with the final transfer currently scheduled for 1993. In order to reduce the carrying costs of this inventory, nearly all of the uranium inventory is being loaned. The loan agreements provide for repayment in kind and include certain guarantees which, in the Company's opinion, will assure such repayment.

In connection with the Company's rate decisions and agreements since 1984, the PSC has allowed, as the cost of approximately 1,314,000 lbs. of NMU uranium utilized at Unit 1 and approximately 294,000 lbs. utilized 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 $50.0 million while the Company's cost is approximately $72.0 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 for regulatory purposes subject to the PSC approval of the comparison of cost to market on an aggregate basis over the life of the project and is included in the Company's investment in NMU for purposes of establishing a necessary valuation reserve for unrecovered costs.

Based upon DOE's uranium price reports which reflect a continued decline in average delivery prices and the anticipated further decline in average delivery prices, the Company expects that, based upon costs allowed in rates to date and the estimated transfer value of remaining inventory, a minimum of $50 million of its investment in NMU may not be recoverable in rates. Accordingly, the Company reduced the carrying value of such investment by $15 million in 1990, $14.5 million in 1989, $7.5 million in 1988 and $13 million prior to 1988. 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, 1991 spot market price of $9.70/pound (contrasted with the last reported DOE price of $19.56/pound), an additional reserve of approximately $5 million would be necessary.

NOTE 4. Bank Credit Arrangements

At December 31, 1990, the Company had $617 million of bank credit arrangements with 24 banks. These credit arrangements consisted of $180 million in commitments under Revolving Credit Agreements, $100 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement for Oswego Facilities Trust, $56 million in one-year commitments under Credit Agreements, $181 million in lines of credit and $100 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreements extend into 1991 and 1992, 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 6).

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, 1990 and are recorded as long-term debt due within one year.

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

	In thousands of dollars	
At December 31:	**1990**	1989
Short-term debt:		
Notes payable	**$ 10,303**	$ 5,000
Bankers acceptances	**55,609**	30,671
	$ 65,912	$ 35,671
Weighted average interest rate *(a)*	**10.06%**	11.40%
For Year Ended December 31:		
Daily average outstanding	**$ 39,329**	$ 80,583
Monthly weighted average interest rate *(a)*	**8.17%**	9.62%
Maximum amount outstanding	**$ 90,748**	$249,300

(a) Excluding fees.

NOTE 5. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1990. 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	$ 84,340	$35,935	$ 613
Oswego Steam Station Unit No. 6 *(b)*	76	$ 263,908	$79,169	$ 1,055
Nine Mile Point Nuclear Station Unit No. 2 *(c)*	41	$1,468,404	$95,349	$17,286

(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 6. 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 8,000,000 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 1988, 1989 and 1990:

	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, 1988:	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
Redemptions			(38,000)	—	(3,800)	(887,199)	—	(22,180)	115
Foreign currency translation adjustment									(106)
Balance December 31, 1990:	136,099,654	$136,100	2,548,000	$210,000	$44,800*(a)*	11,789,204	$80,000	$214,730*(a)*	$1,649,294

**In thousands of dollars* *(a)* Includes sinking fund requirements due within one year

The cumulative amount of foreign currency translation adjustment at December 31, 1990 was $8,046.

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

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

Series	Shares	At December 31, *In thousands of dollars* **1990**	1989	Redemption price per share *(Before adding accumulated dividends)* **December 31, 1990**	Eventual minimum
Preferred $100 par value:					
3.40%	200,000	**$ 20,000**	$ 20,000	**$103.50**	$103.50
3.60%	350,000	**35,000**	35,000	**104.85**	104.85
3.90%	240,000	**24,000**	24,000	**106.00**	106.00
4.10%	210,000	**21,000**	21,000	**102.00**	102.00
4.85%	250,000	**25,000**	25,000	**102.00**	102.00
5.25%	200,000	**20,000**	20,000	**102.00**	102.00
6.10%	250,000	**25,000**	25,000	**101.00**	101.00
7.72%	400,000	**40,000**	40,000	**103.51**	102.36
Preferred $25 par value:					
Adjustable Rate					
Series A	1,200,000	**30,000**	30,000	**25.75**	25.00
Series C	2,000,000	**50,000**	50,000	**25.75**	25.00
		$290,000	$290,000		

MANDATORILY REDEEMABLE PREFERRED STOCK

The Company has certain issues of preferred stock which 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, in thousands, for 1991 through 1995 are as follows: $17,980; $24,980; $31,230; $31,230; and $31,230, respectively.

These series provide for mandatory and optional redemption as follows:

	Shares			In thousands of dollars		Redemption price per share (Before adding accumulated dividends)	
Series	**1990**	1989	At December 31,	**1990**	1989	**December 31, 1990**	Eventual minimum
Preferred $100 par value:							
7.45%	**348,000**	366,000		**$ 34,800**	$ 36,600	**$103.37**	$100.00
10.60%	**100,000**	120,000		**10,000**	12,000	**105.30**	102.65
Preferred $25 par value:							
8.375%	**800,000**	900,000		**20,000**	22,500	**25.77**	25.00
8.70%	**1,000,000**	1,000,000		**25,000**	25,000	*(a)*	25.00
8.75%	**3,000,000**	3,000,000		**75,000**	75,000	*(a)*	25.00
9.75%	**474,000**	540,000		**11,850**	13,500	**25.65**	25.00
10.75%	**320,000**	960,000		**8,000**	24,000	**25.60**	25.00
12.25%	**527,760**	570,820		**13,194**	14,270	*(b)*	25.00
12.50%	**467,444**	505,583		**11,686**	12,640	*(b)*	25.00
Adjustable Rate Series B	**2,000,000**	2,000,000		**50,000**	50,000	**25.75**	25.00
				259,530	285,510		
Less sinking fund redemption requirements				**17,980**	17,980		
				$241,550	$267,530		

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

LONG-TERM DEBT

Long-term debt and long-term debt due within one year at December 31, consisted of the following:

		In thousands of dollars	
Series	Due	**1990**	1989
First mortgage bonds:			
4¾%	1990	**$ —**	$ 50,000
4½%	1991	**40,000**	40,000
12.73%	1992	**30,000**	30,000
13.06%	1992	**50,000**	50,000
12.68%	1992	**20,000**	20,000
** 11%	1993	**—**	50,000
8⅞%	1994	**150,000**	150,000
4⅝%	1994	**40,000**	40,000
9⅛%	1996	**100,000**	100,000
5⅞%	1996	**45,000**	45,000
9⅝%	1997	**100,000**	100,000
6¼%	1997	**40,000**	40,000
9⅞%	1998	**200,000**	200,000
6½%	1998	**60,000**	60,000
10¼%	1999	**100,000**	100,000
10⅜%	1999	**100,000**	100,000
9⅛%	1999	**75,000**	75,000
9½%	2000	**150,000**	—
** 12.95%	2000	**—**	42,669
7⅜%	2001	**65,000**	65,000
9¼%	2001	**100,000**	100,000
7⅝%	2002	**80,000**	80,000
7¾%	2002	**80,000**	80,000
8¼%	2003	**80,000**	80,000
9½%	2003	**38,236**	41,177
9.95%	2004	**65,000**	75,000
9¾%	2005	**150,000**	—
10.20%	2005	**26,000**	29,000
8.35%	2007	**66,640**	66,640
8⅝%	2007	**34,000**	36,000
* 11¼%	2014	**75,690**	75,690
* 11⅜%	2014	**40,015**	40,015
10%	2016	**150,000**	150,000
10%	2016	**100,000**	100,000
* 8⅞%	2025	**75,000**	75,000
Total First Mortgage Bonds		**$2,525,581**	$2,386,191

	In thousands of dollars	
	1990	1989
Promissory notes:		
*8% Series A due June 1, 2004	**46,100**	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 1990-2004	**222,100**	251,100
Swiss Franc Bonds due December 15, 1995	**50,000**	50,000
15.02% Unsecured Notes due 1990	**—**	50,000
Notes, Interest Rate Exchange Agreement	**50,000**	50,000
Revolving credit agreement, Oswego Facilities Trust	**85,050**	63,700
Other	**138,465**	135,512
Unamortized premium (discount)	**(1,519)**	(1,027)
TOTAL LONG-TERM DEBT	**3,529,537**	3,445,836
Less long-term debt due within one year	**216,251**	196,508
	$3,313,286	$3,249,328

* Tax-exempt pollution control related issues
** Retired prior to maturity.

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 million of such notes bear interest at a daily adjustable interest rate (with a Company option to convert to other rates including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 5.09% for 1990 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities.

Notes Payable include a ten-year Swiss franc bond issue equivalent to $50 million 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 for $75 million which expire in 1991 ($50 million in January and $25 million in February). The agreements require the Company to make fixed rate payments which, calculated on a semi-annual bond basis, are equivalent to 7.58% and, in exchange, receive a LIBOR based floating rate payment from a bank. The Company generally uses its own bank credit facilities (See Note 4) as the source of funding. The related interest expense is recorded on a net basis. Such Interest Rate Exchange Agreements include a $25 million agreement held by the Oswego Facilities Trust (Trust).

The arrangements with the Trust provide financing for the construction of a new energy management system. The Trust has a $100 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement. Trust 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 1990 consists of obligations under capital leases of approximately $56 million (See Note 11. "Lease Commitments") and a liability to the U.S. Department of Energy for nuclear fuel disposal of approximately $82.4 million. (See Note 10. "Nuclear Fuel Disposal Costs").

Certain of the Company's debt securities provide for a mandatory sinking fund for annual redemption. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1990, including mandatory sinking fund redemption requirements of approximately $13 million per year, are approximately $205 million, $169 million, $105 million, $213 million and $78 million, respectively.

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 1990 requirements for these series were satisfied by the certification of additional property. The Company anticipates that the 1991 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, 1990, are $6.05 million.

NOTE 7. 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	**1990**	1989	1988
Operating revenues:			
Electric	**$2,669,308**	$2,418,662	$2,343,732
Gas	**485,411**	487,381	456,721
Total	**$3,154,719**	$2,906,043	$2,800,453
Operating income before taxes:			
Electric	**$ 522,947**	$ 466,145	$ 564,275
Gas	**50,228**	50,917	46,528
Total	**$ 573,175**	$ 517,062	$ 610,803
Pretax operating income, including AFC:			
Electric	**$ 543,504**	$ 484,706	$ 574,426
Gas	**51,085**	51,732	47,399
Total	**594,589**	536,438	621,825
Income taxes	**121,114**	105,103	134,451
Other (income) and deductions	**71,728**	(26,504)	6,358
Interest charges	**318,869**	307,056	272,202
Net income	**$ 82,878**	$ 150,783	$ 208,814
Depreciation and amortization:			
Electric	**$ 204,417**	$ 195,372	$ 167,566
Gas	**16,440**	15,501	14,643
Total	**$ 220,857**	$ 210,873	$ 182,209
Construction expenditures (including nuclear fuel):			
Electric	**$ 373,232**	$ 358,390	$ 316,798
Gas	**58,347**	55,102	49,344
Total	**$ 431,579**	$ 413,492	$ 366,142
Identifiable assets:			
Electric	**$6,435,401**	$6,229,107	$5,910,897
Gas	**610,648**	581,900	539,309
Total	**7,046,049**	6,811,007	6,450,206
Corporate assets	**724,265**	751,465	625,835
Total assets	**$7,770,314**	$7,562,472	$7,076,041

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 $22.8 million for 1990, $18.8 million for 1989 and $26.0 million for 1988 (of which $5.5 million for 1990, $5.0 million for 1989 and $7.8 million for 1988 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. In 1990, the Company was unable to make a contribution to the pension plan due to applicable regulations for full funding limitations. 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 1990, 1989 and 1988 included the following components:

	In thousands of dollars		
At December 31,	**1990**	1989	1988
Service cost — benefits earned during the period	**$ 25,700**	$ 21,600	$ 22,900
Interest cost on projected benefit obligation	**39,100**	42,200	56,300
Actual return on Plan assets	**(7,500)**	(108,000)	(84,400)
Deferral of asset gain or (loss)	**(38,300)**	60,200	28,400
Amortization of net obligation	**3,800**	2,800	2,800
Net pension cost	**$ 22,800**	$ 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,	**1990**	1989
Actuarial present value of accumulated benefit obligations:		
Vested benefits	**$336,944**	$250,266
Non-vested benefits	**3,706**	43,338
Accumulated benefit obligations	**340,650**	293,604
Additional amounts related to projected pay increases	**226,305**	163,852
Projected benefits obligation for service rendered to date	**566,955**	457,456
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	**605,500**	600,673
Plan assets in excess of projected benefit obligations	**38,545**	143,217
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	**40,769**	43,561
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	**(55,859)**	(27,837)
Gain from settlement of pension obligations	**—**	(82,752)
Prior service cost not yet recognized in net periodic pension cost	**30,238**	340
Prepaid pension costs included in other current assets and liabilities	**$ 53,693**	$ 76,529

In both 1990 and 1989, 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), respectively. The expected long-term rate of return on plan assets was 9.00% in 1990 and 1989.

Included as an item of income is a portion of a 1989 pension settlement gain realized from the purchase of a group annuity relating to obligations to then 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 $14.9 million for 1990, $11.8 million for 1989 and $12.6 million for 1988.

In December 1990, the FASB issued Statement of Financial Accounting Standards No. 106 entitled "Employers' Accounting for Postretirement Benefits Other Than Pensions". This statement, which becomes effective in 1993, requires, among other things, accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. The Company currently accounts for such costs on a cash basis for both active and retired employees. The Company estimates unfunded accumulated postretirement benefit obligations other than pensions may range between $300 and $400 million in the year of adoption depending primarily upon health care cost assumptions utilized in measuring the liability. The annual expense, using the same cost assumptions, may range from $45 to $65 million. The range of health care cost trend utilized is 6% to 8%. Recognition of net periodic postretirement benefit cost during the years that employees render necessary service will increase the annual expense from that currently recorded on a cash basis; however, the effect on the Company's financial condition of this statement is dependent upon the regulatory treatment afforded accrued postretirement costs.

NOTE 9. Federal and Foreign Income Taxes

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1990	1989	1988
United States	**$141,129**	$234,527	$322,814
Foreign	**19,861**	24,704	16,485
Consolidating eliminations	**(16,993)**	(18,115)	(9,621)
Income before income taxes	**$143,997**	$241,116	$329,678

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*		
	1990	1989	1988
Components of Federal and foreign income taxes:			
Current tax expense: Federal	**$121,275**	$ 24,627	$ 60,173
Foreign	**(2,495)**	4,728	998
	118,780	29,355	61,171
Deferred tax expense: Federal	**(8,096)**	70,851	66,996
Foreign	**10,430**	4,897	6,284
	2,334	75,748	73,280
Income taxes included in Operating Expenses	**121,114**	105,103	134,451
Current Federal income tax credits included in Other Income and Deductions	**(32,756)**	(24,755)	(29,068)
Deferred Federal income tax expense (credits) included in Other Income and Deductions	**(27,239)**	9,985	15,481
Total	**$ 61,119**	$ 90,333	$120,864
Components of deferred Federal and foreign income taxes *(Note 1):*			
Depreciation	**$ 84,591**	$ 90,920	$116,397
Investment tax credit	**(4,014)**	(9,116)	(392)
Alternative minimum tax	**(16,843)**	(17,363)	(33,786)
Construction overheads	**(10,324)**	1,386	(2,826)
Recoverable energy and purchased gas costs	**(27,897)**	25,987	8,664
Unbilled revenues	**(13,898)**	(6,686)	4,912
Deferred operating expenses	**24,146**	4,698	—
Deferred transmission revenues	**(6,569)**	—	—
Nuclear settlement disallowance	**(32,964)**	—	—
Reserve for NM Uranium, Inc.	**(5,013)**	(3,796)	(1,964)
Other (net)	**(16,120)**	(297)	(2,244)
Deferred Federal income taxes (net)	**$ (24,905)**	$ 85,733	$ 88,761
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	**$ 48,959**	$ 81,979	$112,091
Reduction (increase) attributable to flow-through of certain tax adjustments:			
Depreciation	**(30,569)**	(30,645)	(18,959)
Allowance for funds used during construction	**8,728**	7,130	3,747
Taxes, pensions and employee benefits capitalized for accounting purposes	**1,934**	(273)	3,929
Real estate taxes on an assessment date basis	**(500)**	1,934	2,537
Deferred investment tax credit amortization	**7,820**	9,381	10,092
Other (net)	**427**	4,119	(10,119)
	(12,160)	(8,354)	(8,773)
Federal and foreign income taxes	**$ 61,119**	$ 90,333	$120,864

NOTE 10. Nuclear Operations

The Company is the owner and operator of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) and the operator and a 41% co-owner of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2). Ownership of Unit 2 is shared with Long Island Lighting Company (18%), New York State Electric & Gas Corporation (18%), Rochester Gas and Electric Corporation (14%), and Central Hudson Gas & Electric Corporation (9%). Output of Unit 2, which has a design capability of 1,084,000 kw., is shared in the same proportions as the cotenants' respective ownership interests. For regulatory purposes, April 5, 1988 has been recognized as the commercial operation date for Unit 2. Unit 1 has a design capability of 610,000 kw. and was placed in commercial operation in 1969.

Since December 1988, the Nine Mile Point Nuclear Station (Units 1 and 2) has been, and continues to be, categorized as requiring close monitoring by the Nuclear Regulatory Commission (NRC). Contingencies involving the Company's ownership of these facilities are discussed below.

Institute of Nuclear Power Operations Evaluation: In August 1990, the Institute of Nuclear Power Operations (INPO), an industry sponsored oversight group, performed a site evaluation of Nine Mile Point Nuclear Station (Units 1 and 2).

INPO reported deficiencies in several key areas related to operator performance, enforcement of station standards, documentation of root causes of in-house events and engineering support of plant operations. Even though a number of these issues had been previously noted in the last INPO evaluation, INPO did observe a strong commitment and positive attitude toward improving performance.

The Company has provided to INPO a response to the findings and has made commitments to INPO to address those findings.

Unit 1 Thirty-One Month Outage and Restart: Unit 1 commenced operations in 1969 and has operated at an average capacity factor in excess of 55% for the twenty-one year period through 1990, including the effects of the outage discussed below. Unit 1 was taken out of service in December 1987 for repairs to its feedwater system. During those repairs, the Company decided to proceed from that 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 perform additional in-service inspections required under codes which are now effective and to perform a substantial amount of work to upgrade and refurbish the Unit.

In July 1988, the Staff of the NRC (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 was developed and approval for restart was received from the NRC Staff.

The Company submitted a comprehensive Restart Action Plan to correct the root causes of the concerns raised by the NRC Staff to the NRC Region I Administrator which was approved on September 29, 1989. On July 13, 1990, the Company submitted a report to the NRC Region I Administrator indicating that the Company was prepared to restart Unit 1. On July 27, 1990, the Company received approval to restart Unit 1 based on the NRC's determination that the Company had taken all necessary actions to ensure public health and safety. The process of restarting Unit 1 began on July 29, 1990. On October 23, 1990, the NRC granted approval to bring the Unit to full power. Since returning to full service in October 1990, Unit 1 has operated at an average capacity factor in excess of 75% through December 31, 1990. On February 12, 1991, a malfunction in one of the turbine control systems caused an automatic shutdown of Unit 1, and the Company decided to proceed into an eight-week mid-cycle outage, which was originally scheduled to begin on March 2, 1991, to conduct required inspections.

PSC Investigation of the Unit 1 Thirty-One Month Outage: In May 1988, the Attorney General of the State of New York filed a petition with the New York State Public Service Commission (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 (CPB) 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 Interim Relief Agreement by approximately $40.7 million and earnings per share during 1989 by approximately $.20. The Company also absorbed its share of any additional 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.

The Interim Relief Agreement prevented the need for the Company to litigate at that time the question of the responsibility for replacement power costs during the outage and thus permitted continued concentration of the Company's resources in 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.

Unit 1 did not return to service by June 30, 1989 and the Interim Relief Agreement expired by its terms. The Company entered into an agreement (the 1989 Agreement) dated August 31, 1989, with the Staff of the PSC, the New York Consumer Protection Board, the New York Attorney General and Multiple Intervenors. Pursuant to the 1989 Agreement, the parties thereto, and the PSC, agreed to, among other things, 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 remained subject to the Unit 1 outage prudence investigation. With the expiration of the Interim Relief Agreement, the Company began collecting from customers and recording as revenue the replacement power costs incurred after June 30, 1989.

Based upon assumptions utilized in determining the amount of replacement power costs occasioned by the Unit 1 outage, the Company has estimated that, through the end of October 1990, when Unit 1 returned to full service, it has collected from ratepayers approximately $195 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, the Company has estimated that it has already absorbed approximately $68 million of replacement power costs, including amounts not collected pursuant to the Interim Relief Agreement, and approximately $132 million of incremental Unit 1 operating and maintenance costs generally 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 depends upon seasonal factors, relative demand and availability of capacity, as well as assumptions utilized in estimating replacement power costs incurred during the outage. During the period of the outage, replacement power costs have averaged approximately $328,000 per day, determined by using a New York Power Pool/Canadian supplier average cost per KWH.

The Company reached an agreement with certain other parties as to a temporary annual rate increase, which was effective January 1, 1991 and resulted in an increase in electric rates of $162.8 million and a $27.2 million increase in gas rates. For the purpose of establishing these temporary rates, certain assumptions were made relating to issues under negotiation pursuant to the 1989 Agreement, including a liability to customers of approximately $130 million for Unit 1 and Unit 2 replacement power costs ($18 million of which reflects the terms of the 1990 Unit 2 Settlement discussed below under Unit 2 Ratemaking and Cost Settlement; Refueling Outage), a write-off of $10 million of deferred capacity charges occasioned by the Unit 1 outage, and a reduction in the allowed return on equity from 12.5% to 11.5% in the first rate year to begin returning these funds to customers. These assumptions, along with others that supported the 1990 Temporary Rate Agreement, have been confirmed in the 1991 Stipulation which establishes permanent rates for the period July 1, 1990 to December 31, 1992. The 1991 Stipulation is subject to PSC approval, which is expected prior to July 1, 1991. The Company accrued the loss associated with the estimated customer liability related to Unit 1 replacement power costs, as well as the loss related to the 1990 Unit 2 Settlement Agreement based upon management's assessment of the probable approval by the PSC of the multiyear rate plan, prudence issues and expected level and conditions of the incentive return mechanism, as well as the approval by the PSC of the temporary rate increase on December 19, 1990. The Company is unable to predict whether the PSC will approve the 1991 Stipulation; however, the Company believes that based upon the participation of the PSC Staff and other intervenors in the negotiating process, any adjustment relative to replacement power cost liability that might result from PSC approval of the 1991 Stipulation should not have a significant effect on the Company's financial condition or results of operations.

Unit 2 Ratemaking and Cost Settlement; Refueling Outage: A settlement of a PSC proceeding to investigate the prudence of costs incurred for the construction of Unit 2 was approved in 1986. The cost settlement established a cap on the allowed rate base cost of Unit 2; however, certain issues arose regarding the subsequent implementation of the cost settlement. In June 1990, the Company and cotenant companies reached a settlement (1990 Unit 2 Settlement) with the PSC Staff and other intervenors with respect to such Unit 2 settlement cap issues, allocation of net contractor litigation proceeds, Unit 2 operating prudence and established a mechanism for setting prospective operating and maintenance costs. The 1990 Unit 2 Settlement was approved by the PSC on October 24, 1990. The 1990 Unit 2 Settlement established a final level of allowed Unit 2 costs and estops the PSC from asserting that future capital additions are subject to the 1986 Unit 2 cost 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. Based upon the Unit 2 loss recognized in 1987 with the Company's adoption of Statement of Financial Accounting Standards No. 90 and the terms of the 1990 Unit 2 Settlement, the Company reduced its Unit 2 project cost disallowance reserve in 1990 by approximately $6 million, before federal income taxes. The Company accrued in 1990 a loss for the future refund of replacement power costs with respect to the first year of Unit 2 operation, as established in the 1990 Unit 2 Settlement Agreement, in the amount of $18 million, before federal income tax.

Unit 2's first refueling outage began on September 5, 1990 and was expected to be completed by mid-December. However, the outage was extended into January 1991 as a result of increased work scope. On January 30, 1991, Unit 2 returned to service.

Based on the results of an Inservice Inspection on the Unit, a potential weld defect was identified on a nozzle to pipe weld. Technical measures were taken to mitigate future growth of the potential weld defect; however, it has been agreed between the Company and the NRC that the weld will be reinspected within five to nine months of returning the Unit to service after the completion of the current outage. Performing this inspection would require a shutdown of the Unit for ten days. The Company is currently evaluating alternatives which could mitigate this outage duration.

The next refueling outage for Unit 2 is expected to begin on February 29, 1992.

Unit 2 Contractor Litigation: 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. (SWEC) (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. SWEC has filed its answer which disagrees with the Company's claim. The ITT defendants have filed an answer, also disputing the allegations of the Company and cotenants. Their answer includes an allegation against the Company and the cotenants, that all claims are barred by contract close-out agreements. The ITT defendants are requesting dismissal of the complaint, and judgment in their favor on the counterclaim, in such amount as they may prove at trial, together with interest and costs. The Company is unable to predict the outcome of the litigation.

Based on the 1990 Unit 2 Settlement approved by the PSC Staff discussed above under "Unit 2 Ratemaking and Cost Settlement", proceeds of the 1990 litigation settlement regarding Main Steam Isolation Valves and the proceeds, if any, of the litigation against SWEC, ITT Fluid Products Corporation, and ITT Fluid Technology Corporation, after deducting the associated litigation costs, will be combined and allocated equally between shareholders and ratepayers.

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 $446 million at that time ($222 million in 1990 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 $540 million ($94 million in 1990 dollars). Effective January 1, 1991, with the approval of a temporary rate increase of $190 million, an annual allowance was reflected to decommission each Unit based upon the cost of decommissioning estimates noted above. The temporary rate increase is subject to adjustment based upon the resolution of permanent rate negotiations. Through December 31, 1990, the Company has recovered approximately $40.5 million of decommissioning costs in rates for both units and these amounts have been considered in establishing the annual decommissioning allowances needed to decommission the 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 funds to provide for the cost of decommissioning activities of contaminated portions of nuclear facilities into an external trust. Further, the NRC established guidelines for determining minimum amounts that must be available in such a 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 $344 million and $446 million in future dollars. As of December 31, 1990, the Company had deposited in an external trust $3.3 million for Unit 1 and $.4 million for its share of Unit 2. Annual amounts necessary to meet the minimum NRC funding requirements have been reflected in the 1990 Temporary Rate Increase discussed above. The Company has also included annual amounts consistent with the minimum funding requirements in its request for rate relief filed with the PSC in January 1991 pursuant to negotiation of rate awards for the years ended June 30, 1992 and 1993. The Company can provide no assurance that the PSC will approve the level of allowance reflected in the first rate year, or in the second and third rate years. On July 26, 1990, the Company filed a decommissioning report for each Unit with the NRC which included 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 Amendments Act of 1988, (the Act), the public liability limit with respect to a nuclear accident at a licensed reactor is approximately $7.5 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 Act also provides, 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 would 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 until 2010 will inhibit operation of either Unit.

NOTE 11. Commitments and Contingencies

Construction Program: The Company is committed to an ongoing construction program to assure reliable delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1991 through 1995 will require approximately $2.32 billion, excluding AFC, nuclear fuel and certain overheads capitalized. For the years 1991 through 1995, the estimates are $443 million, $452 million, $469 million, $502 million and $453 million, respectively. These amounts are expected to be reviewed by management in 1991 and thereafter on a regular basis.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1991, 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	904,000	$16,781,000
St. Lawrence — hydroelectric project	2007	104,000	1,248,000
Blenheim-Gilboa — pumped storage generating station	2002	270,000	7,452,000
FitzPatrick — nuclear plant	year-to-year basis	63,000(a)	6,110,000
		1,341,000	$31,591,000

(a) 24,000 kw for summer of 1991; 51,000 kw for winter of 1991-92.

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 $57.2 million, $52.8 million and $46.3 million for the years 1990, 1989 and 1988, 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 $198 million was paid to Qualifying Facilities in 1990 for

3,041,000,000 kwh of energy and associated capacity. Through December 31, 1990, 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. Based upon contacts entered into and approved to date, the Company will be obligated to purchase the power generated by these facilities having an aggregate amount of capacity in each of the following periods: 1,044 MW in 1991, 1,695 MW in 1992, 2,391 MW in 1993, 2,973 MW in 1994 and 3,013 MW in 1995. 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 $56.1 million and $59.3 million at December 31, 1990 and 1989, 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 $600 million, a substantial portion of which relates to a transmission line facility with an unelapsed term of 36 years. Annual future minimum rental commitments for the period 1991-1995 range between $22 million and $34 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, 1990 and 1989, $200 and $177 million, respectively, of receivables had been sold under this agreement. The undivided interest in the designated pool of receivables was sold with limited recourse. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold.

Litigation: Stockholder Derivative Suit: In May 1988, a stockholder 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 damages claimed was not specified. In May 1989, the District Court dismissed all counts of the complaint.

In October, 1990, the same plaintiffs commenced a stockholder derivative action against the same defendants in New York State Supreme Court, Onondaga County, seeking to recover on behalf of the Company damages alleged to have arisen from the construction and operation of both Unit 1 and Unit 2. The amount of damages claimed was not specified. Discovery proceedings have commenced. The parties are continuing to pursue settlement of this action; however, the Company is unable to predict the outcome of the action or the impact, if any, on the Company's financial position or results of operations.

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.

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 stock. 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. Applying the methodology set forth in the indemnity schedules, the Company's estimated liability for dividends paid through 1990 is approximately $41 million. 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 should 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 68 identified sites, of which 38 are Company-owned. Of the 38 Company-owned sites, 24 are coal gasification sites and 14 are industrial waste sites. Of these Company-owned sites, 14 are listed on the New York State Registry of Inactive Hazardous Waste Sites and 1 of the 14 is also on the Federal National Priorities List. The 30 remaining sites with which the Company is associated are generally alleged to be industrial waste sites to which the Company may be required to contribute some proportionate share towards investigation and clean-up. Of these sites, 24 are included in the New York State Registry of Inactive Hazardous Waste Sites and 10 are on the Federal National Priorities List. The Company can provide no assurance that additional sites with which it is or may be associated will not be identified in the future as requiring investigation or remediation, or as to the Company's potential liability relative thereto.

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 who the Company believes should bear some, if not all, of the cost of remediation. After site investigations have been completed, the Company expects to be able to determine the remedial actions necessary and estimate the attendant costs for restoration. However, since 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, the ultimate cost of remedial actions may change substantially as investigation and remediation progresses.

The Company has completed various phases of studies on seven Company-owned sites and has submitted those studies to the appropriate regulatory agency. Based upon the findings of the studies and internal assessments of other sites the Company believes may require some level of remediation, total expenditures for Company-owned sites could approximate $300 million to be incurred through 2000. Of this amount, the Company believes that $29 million may be recoverable from other responsible parties, although the Company has not yet undertaken any action against these other parties and can provide no assurance as to whether any amounts will actually be recovered. Of the 38 Company-owned sites, only 15 sites are anticipated to require clean-up. For sites where the Company has not conducted any investigation, an estimate of clean-up costs of a "typical" remediation effort, as developed by the Environmental Protection Agency (EPA), was utilized. Because the nature and extent of contamination varies from site to site, the total cost of remediation is likely to vary from the EPA estimate.

With respect to other sites with which the Company is associated, all are listed on either a state or federal registry. Total costs to investigate and remediate these sites are estimated to be approximately $436 million through 2000. The Company estimates its share may be less than $10 million. Actual Company expenditures for these sites are dependent upon the total cost of investigation and remediation, the determination of the Company's share of responsibility for such costs and the financial viability of other identified responsible parties.

The Company believes that costs incurred in the investigation and restoration process are recoverable in the ratesetting process.

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. Discovery has begun and is expected to be concluded in 1991. By letter dated November 16, 1989, Long Lake's counsel claimed damages of $214 million 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, for 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.

Tax assessments: The Internal Revenue Service (IRS) has completed examinations of the Company's Federal income tax returns for 1983 through 1986. The IRS has proposed various adjustments to the Company's federal income tax liability for these years which, in combination with a reduction in investment tax credit carryforward from 1981 and 1982 resulting from a 1990 settlement with the IRS of those years, could increase Federal income tax liability by approximately $67 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 the assessments, if any, are generally recoverable in rates.

Excluded from this potential increase in tax liability is approximately $13.6 million that results from issues underlying a refund received by the Company in 1990 as well as an anticipated refund in 1991. The refund, amounting to $10.5 million excluding interest, was related to 1981 and 1982. Another refund of $3.7 million relating to the same issue as applied to 1980 is expected to be received in 1991. The refunds for these periods will reduce the investment tax credit carryover that was utilized in the period 1983 to 1986, thus increasing the Company's tax liability during that period. The Company has deferred the refund of tax to be offset by the future tax liability, and has agreed to equally share with customers the interest refunded, offset by the anticipated interest expenses on the future liability.

The IRS has recently begun an examination of the Company's federal income tax returns for the years 1987 and 1988. The Company expects that several key issues involving Unit 2, including its tax in-service date and cost basis for investment tax credit purposes, will be raised during the examination. To the extent the IRS is able to sustain disallowances in those areas, the Company may have to absorb a portion of any disallowance pursuant to the 1990 Unit 2 Settlement Agreement (See Note 10).

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 generally be recoverable by the Company through the ratesetting process.

NOTE 12. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income (loss) and earnings (loss) per common share by quarters from 1990, 1989 and 1988 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, **1990**	**$781,270**	**$ 63,531**	**$(104,807)**	**$(.85)**
1989	734,038	88,139	9,068	(.01)
1988	678,858	65,918	(3,808)	(.12)
September 30, **1990**	**$682,114**	**$128,191**	**$ 60,128**	**$ .37**
1989	612,971	101,546	36,322	.19
1988	608,393	113,496	52,297	.31
June 30, **1990**	**$737,860**	**$103,750**	**$ 35,756**	**$ .18**
1989	710,582	87,908	34,147	.17
1988	702,678	126,718	46,823	.27
March 31, **1990**	**$953,475**	**$156,589**	**$ 91,801**	**$ .60**
1989	848,452	134,366	71,246	.44
1988	810,524	170,221	113,502	.77

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 the fourth quarter of 1990, 1989 and 1988, the Company accrued $15 million ($.07 per common share), $14.5 million ($.08 per common share) and $7.5 million ($.04 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. NM Uranium, Inc.). In the fourth quarter of 1990, the Company reflected a loss of $140 million ($.68 per common share) relating to nuclear replacement power costs disallowed associated with Unit 1 and Unit 2 outages (See Note 10. Nuclear Operations).

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, 1990 and 1989, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1990, 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 discussed in Note 11, the Company is a defendant in a lawsuit alleging violations of certain federal and state anti-trust 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 1990 and 1989 financial statements.

Price Waterhouse

Syracuse, New York
January 31, 1991
(except for Note 10, Paragraph 14
which is as of February 20, 1991)

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 appears on page 39 of 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 five 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.

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. The Company presently estimates that none of the 1990 preferred stock dividends will constitute a return of capital and therefore all of such dividends are subject to Federal tax as ordinary income.

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

1990	Dividends paid per share	Price range High	Price range Low
1st Quarter	—	$14 1/2	$12 7/8
2nd Quarter	—	14 3/8	12 1/8
3rd Quarter	—	14 3/4	11 3/4
4th Quarter	—	13 3/4	12
1989			
1st Quarter	$.30	$13 3/4	$11 1/2
2nd Quarter	.30	12 1/8	10 3/4
3rd Quarter	—	14 3/8	11 1/8
4th Quarter	—	14 3/4	13 3/8

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 Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) and the issues associated with a number of outstanding regulatory proceedings, determined to omit the third quarter common stock dividend. No common stock dividends have been paid since that time. Resumption of payment of the common stock dividend will depend on the resolution of issues affecting the long-range financial condition of the Company. The 1989 Agreement provided that any party to that Agreement could withdraw therefrom if the Company resumed 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. Although the Unit 1 operating requirement was satisfied on November 26, 1990, in considering the resumption of common stock dividend payments or the level at which they would be resumed, the Board of Directors must consider, among other things, the nature, amount and timing of permanent rate relief resulting from the multiyear plan negotiated pursuant to the 1989 Agreement. The Company, Public Service Commission Staff (PSC Staff) and others submitted an agreement (the 1991 Stipulation) to the Public Service Commission (PSC) on February 19, 1991 to establish permanent rates for the year ended June 30, 1991 at the level of temporary rates approved by the PSC on December 19, 1990, as well as establish permanent rates through December 31, 1992. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the 1989 Agreement, the Temporary Rate Agreement and the 1991 Stipulation. The Company expects that the 1991 Stipulation will be approved by the PSC by July 1, 1991, although no such assurance can be provided. Approval of the 1991 Stipulation by July 1, 1991 will not in itself be determinative of the timing of the resumption of the common stock dividend.

Other Stockholder Matters: The holders of Common Stock are entitled to one vote per share but may not cumulate their votes for the election of Directors. Whenever dividends on Preferred Stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect a majority of the Board of Directors. Whenever dividends on any Preference

Stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set apart for payment, the holders of such stock can elect two members to the Board of Directors. No dividends on Preferred Stock are now in arrears and no Preference Stock is now outstanding.

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

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

At year end, about 133,000 stockholders owned common shares of the Company and about 6,200 held preferred stock. The chart below summarizes common stockholder ownership by size of holding:

Size of holding (Shares)	Total stockholders	Total shares held
1 to 99	50,080	1,642,511
100 to 999	74,677	20,677,203
1,000 or more	8,389	113,779,940
	133,146	136,099,654

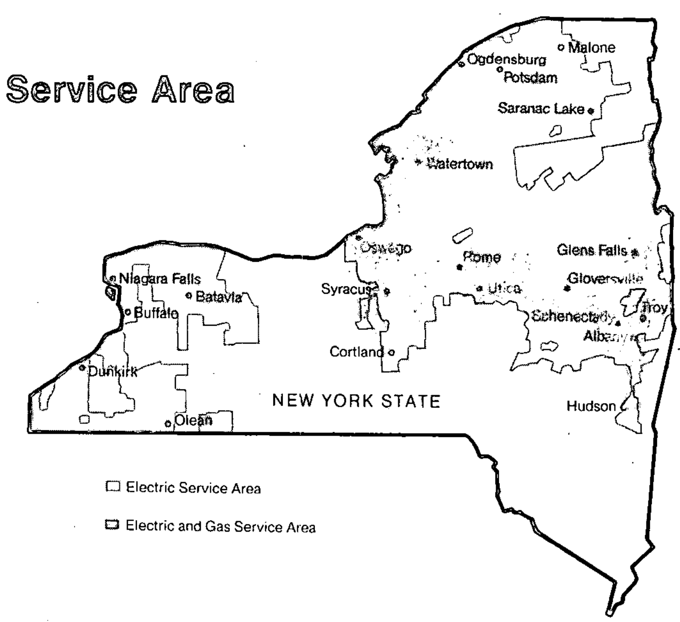
Serving Our Customers in Upstate New York

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

Our electric system meets the needs of more than 1.5 million residential, commercial and industrial customers, with power supplied by hydroelectric, coal, oil, natural gas and nuclear generating units. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

Our 6,800-mile natural gas system provides service to nearly 475,000 residential and business customers on a retail basis, as well as a growing number of customers from whom we transport gas that they purchase directly from suppliers.

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



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 the 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.

	1990	1989	1988	1987	1986
Operations: *(000's)*					
Operating revenues	**$3,154,719**	$2,906,043	$2,800,453	$2,623,430	$2,660,319
Income before cumulative effect of accounting change	**82,878**	150,783	208,814	57,786	397,865
Cumulative effect on prior years of adoption of SFAS No. 90	—	—	—	(615,000)	—
Net income (loss)	**82,878**	150,783	208,814	(557,214)	397,865
Proforma balance available for common stock — giving effect to the retroactive application of SFAS No. 90	—	—	—	5,769	16,048
Common stock data:					
Book value per share at year end	**$14.37**	$14.07	$13.87	$13.82	$20.23
Market price at year end	**13 1/8**	14 3/8	13	12	16 3/4
Ratio of market price to book value at year end	**91.4%**	102.2%	93.7%	86.8%	82.8%
Dividend yield at year end	**0.0%**	0.0%	9.2%	10.0%	12.4%
Earnings per average common share before cumulative effect of accounting change	**$ .30**	$ .78	$ 1.21	$ .05	$ 2.71
Cumulative effect on prior years of adoption of SFAS No. 90 per average common share	—	—	—	(4.83)	—
Earnings per average common share	**.30**	.78	1.21	(4.78)	2.71
Proforma earnings per average common share — giving effect to the retroactive application of SFAS No. 90	—	—	—	.05	.13
Rate of return on common equity	**2.1%**	5.6%	8.7%	12.7%*	13.6%
Dividends paid per common share	**$ .00**	$ .60	$ 1.20	$ 1.64	$ 2.08
Dividend payout ratio	**0.0%**	76.9%	99.2%	—	76.8%
Capitalization: *(000's)*					
Common equity	**$1,955,118**	$1,914,531	$1,881,394	$1,781,518	$2,571,491
Non-redeemable preferred stock	**290,000**	290,000	290,000	290,000	290,000
Redeemable preferred stock	**241,550**	267,530	295,510	355,490	347,470
Long-term debt	**3,313,286**	3,249,328	2,995,748	2,903,921	2,799,605
Total	**5,799,954**	5,721,389	5,462,652	5,330,929	6,008,566
First mortgage bonds maturing within one year	**40,000**	50,000	33,000	50,000	50,000
Total	**$5,839,954**	$5,771,389	$5,495,652	$5,380,929	$6,058,566
Capitalization ratios: *(including first mortgage bonds maturing within one year):*					
Common stock equity	**33.5%**	33.2%	34.2%	33.1%	42.5%
Preferred stock	**9.1**	9.6	10.7	12.0	10.5
Long-term debt	**57.4**	57.2	55.1	54.9	47.0
Financial ratios:					
Ratio of earnings to fixed charges	**1.41**	1.71	2.10	1.65**	2.98
Ratio of earnings to fixed charges without AFC	**1.35**	1.66	2.06	1.54**	2.42
Ratio of AFC to balance available for common stock	**52.8%**	18.3%	6.9%	—	48.2%
Ratio of earnings to fixed charges and preferred stock dividends	**1.17**	1.41	1.67	1.04**	2.35
Proforma Ratios — giving effect to the retroactive application of SFAS No. 90:					
Earnings to fixed charges	—	—	—	1.65	1.28
Earnings to fixed charges and preferred stock dividends	—	—	—	1.04	1.05
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	**36.9%**	36.5%	34.6%	35.6%	38.0%
Maintenance, depreciation and amortization	**14.4**	14.4	15.1	12.1	11.4
Total taxes	**14.4**	15.3	16.1	16.7	18.1
Operating income	**14.3**	14.2	17.0	18.5	16.6
Balance available for common stock	**1.3**	3.6	5.7	—	12.9
Miscellaneous: *(000's)*					
Gross additions to utility plant	**$ 431,579**	$ 413,492	$ 366,142	$ 457,109	$ 784,137
Total utility plant	**8,702,741**	8,324,112	7,967,625	7,691,069	8,445,993
Accumulated depreciation and amortization	**2,484,124**	2,283,307	2,090,170	1,913,687	1,763,443
Total assets	**7,770,314**	7,562,472	7,076,041	6,794,098	7,611,203

*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.

Electric and Gas Statistics

ELECTRIC CAPABILITY

Thousands of kilowatts

At January 1,	1991	%	1990	1989
Thermal:				
Coal fuel:				
Huntley, Niagara River	715	9	715	715
Dunkirk, Lake Erie	579	8	585	560
Total coal fuel	1,294	17	1,300	1,275
Residual oil fuel:				
Albany, Hudson River**	400	5	400	400
Oswego, Lake Ontario***	1,661	22	1,654	1,571
Roseton, Hudson River	300	4	300	300
Middle distillate oil fuel				
8 Combustion turbine units	211	3	230	237
Total oil fuel	2,572	34	2,584	2,508
Nuclear fuel:				
Nine Mile Point, Lake Ontario	1,051	14	1,050	1,054
Purchased—firm contract				
Power Authority—				
FitzPatrick, Lake Ontario	63	1	77	53
Total nuclear fuel	1,114	15	1,127	1,107
Independently owned sources	304	4	171	121
Total thermal sources	5,284	70	5,182	5,011
Hydro:				
Owned and leased hydro stations (74)	708	9	680	695
Purchased—firm contracts:				
Power Authority —				
Niagara River	904	12	915	1,077
St. Lawrence River	104	1	104	—
Blenheim-Gilboa				
Pumped Storage Plant	270	4	395	295
Other	326	4	298	294
Total hydro sources	2,312	30	2,392	2,361
Total capability*	7,596	100	7,574	7,372

	1990	1989	1988
Electric peak load during year	5,792	6,376	6,220

*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.

ELECTRICITY GENERATED AND PURCHASED

Millions of kw-hrs.

	1990	%	1989	%	1988	%
Thermal:						
Generated						
Coal	8,678	23	9,013	24	7,894	21
Oil	7,109	18	6,470	17	7,444	19
Nuclear	2,975	8	1,762	5	1,460	4
Natural gas	1,950	5	2,456	6	1,070	3
Purchased—						
Nuclear from						
Power Authority	362	1	387	1	306	1
Independently owned						
sources	1,600	4	830	2	612	1
Total thermal	22,674	59	20,918	55	18,786	49
Hydro:						
Generated	4,024	10	3,675	10	3,171	8
Purchased from						
Power Authority	6,624	17	6,721	17	7,014	18
Independently owned						
sources	1,441	4	1,203	3	978	3
Total hydro	12,089	31	11,599	30	11,163	29
Other purchased power — various sources	3,674	10	5,765	15	8,192	22
Total generated and purchased	38,437	100	38,282	100	38,141	100

ELECTRIC STATISTICS

	1990	1989	1988
Electric sales *(Millions of kw-hrs.)*			
Residential	10,310	10,357	10,099
Commercial	11,623	11,432	11,182
Industrial	11,874	12,184	11,745
Municipal service	226	228	237
Other electric systems	1,511	1,195	1,732
	35,544	35,396	34,995
Electric revenues *(Thousands of dollars)*			
Residential	$ 917,057	$ 842,523	$ 805,523
Commercial	978,684	874,187	827,918
Industrial	543,365	486,108	458,332
Municipal service	44,825	42,294	41,231
Other electric systems	69,821	58,056	60,214
Miscellaneous	115,556	115,494	150,514
	$2,669,308	$2,418,662	$2,343,732
Electric customers *(Average)*			
Residential	1,361,961	1,345,033	1,324,367
Commercial	145,231	143,232	140,237
Industrial	2,309	2,334	2,322
Other	3,158	3,163	3,182
	1,512,659	1,493,762	1,470,108
Residential *(Average)*			
Annual kw-hr. use per customer	7,570	7,700	7,626
Cost to customer per kw-hr.	8.89¢	8.14¢	7.98¢
Annual revenue per customer	$673.33	$626.40	$608.23

GAS STATISTICS

	1990	1989	1988
Gas sales *(Thousands of dekatherms)*			
Residential	49,955	52,893	51,065
Commercial	22,823	23,152	23,951
Industrial	4,116	2,612	4,274
Other gas systems	1,723	2,020	2,158
Total sales	78,617	80,677	81,448
Transportation of customer-owned gas	34,242	33,769	27,244
Total gas delivered	112,859	114,446	108,692
Gas revenues *(Thousands of dollars)*			
Residential	$307,217	$317,532	$289,026
Commercial	128,462	125,912	119,929
Industrial	19,322	12,309	19,008
Other gas systems	7,907	9,272	9,363
Transportation of customer-owned gas	22,100	19,831	13,841
Miscellaneous	403	2,525	5,554
	$485,411	$487,381	$456,721
Gas customers *(Average)*			
Residential	431,588	424,494	417,360
Commercial	37,011	35,925	35,017
Industrial	272	280	323
Other	2	2	2
Transportation	567	516	403
	469,440	461,217	453,105
Residential *(Average)*			
Annual dekatherm use per customer	115.7	124.6	122.4
Cost to customer per dekatherm	$6.15	$6.00	$5.66
Annual revenue per customer	$711.83	$748.02	$692.51
Maximum day gas sendout *(dekatherms)*	714,122	802,909	818,128

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 7, 1991. A notice of the meeting, proxy statement and form of proxy will be sent in early April to holders of common stock.

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 the 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, 1991 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
20 West Broadway, New York, N.Y. 10007-2192

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.

Officers

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

John M. Endries
President

B. Ralph Sylvia
Executive Vice President, Nuclear
(Effective 11/15/90)

David J. Arrington
Senior Vice President, Human Resources
(Effective 12/1/90)

Anthony J. Baratta, Jr.
Senior Vice President
(Named Exec. Vice President, HYDRA-CO, 10/1/90)

John P. Hennessey
Senior Vice President, Electric Customer Service

Gary J. Lavine
Senior Vice President, Legal & Corporate Relations
(Effective 10/1/90)

Robert J. Patrylo
Senior Vice President, Gas Customer Service
(Effective 12/1/90)

John W. Powers
Senior Vice President, Finance and Corporate Services

Michael P. Ranalli
Senior Vice President, Electric Supply and Delivery

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

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

Joseph F. Firlit
Vice President, Nuclear Generation
(Effective 7/1/90)

Gerald D. Garcy
Vice President, Power Contracts
(Retired 12/31/90)

James P. Gorman
Vice President, Corporate Audits

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

Darlene D. Kerr
Vice President, Gas Marketing and Rates
(Effective 2/1/91)

Samuel F. Manno
Vice President, Purchasing & Materials Management

Douglas R. McCuen
Vice President, Government & Regulatory Relations
(Effective 2/1/91)

James A. Perry
Vice President, Quality Assurance

Nicholas L. Prioletti, Jr.
Controller

Arthur W. Roos
Treasurer

Richard H. Ryczek
Vice President, Gas Customer Service Operations

Jack R. Swartz
Vice President, Regional Operations

Carl D. Terry
Vice President, Nuclear Engineering and Licensing

Stanley W. Wilczek, Jr.
Vice President, Nuclear Support
(Effective 9/1/90)

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

Directors

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

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

Douglas M. Costle *(D)*
Dean, Vermont Law School, South Royalton, VT

Edmund M. Davis *(A,B,C,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, Cooperstown

John M. Endries *(G)*
President

Dr. Bonnie Guiton *(D)*
President and Chief Executive Officer, Earth Conservation Corps, Washington, D.C.

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 of Southern California

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

A. Member of the Executive Committee
B. Member of the Compensation & Succession Committee
C. Member of the Audit Committee
D. Member of the Committee on Public Policy & Environmental Affairs
E. Member of the Finance Committee
F. Member of the Nuclear Oversight Committee
G. Member of the Self-Assessment Committee

NIAGARA MOHAWK
300 Erie Boulevard West
Syracuse, New York 13202