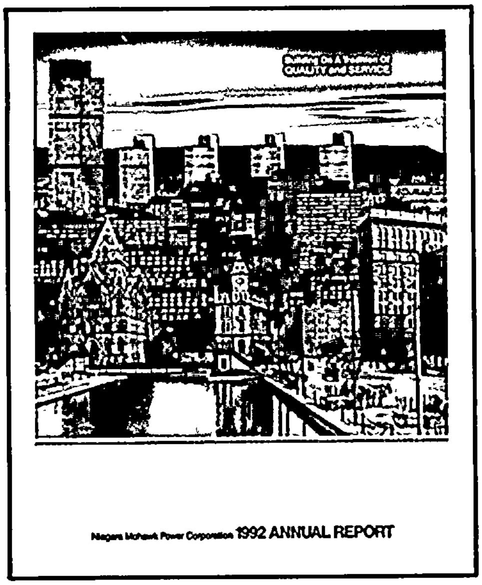
Niagara Mohawk Power Corporation 1992 ANNUAL REPORT



ON THE COVER: A composite photograph illustrates the solid foundation of quality and service Niagara Mohawk has built through the decades with a look back at a downtown Syracuse street scene of 1912 and the present-day Albany skyline. The Erie Canal, shown in the foreground, is a reminder of the expanse of the company's service territory which reaches from Buffalo in the west to Albany in the east.

PHOTO CREDITS: Historical photograph of Syracuse courtesy of Syracuse Blue Print Company, Inc. Albany skyline photograph courtesy of Eastman Kodak Company, Rochester, New York.

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

Contents

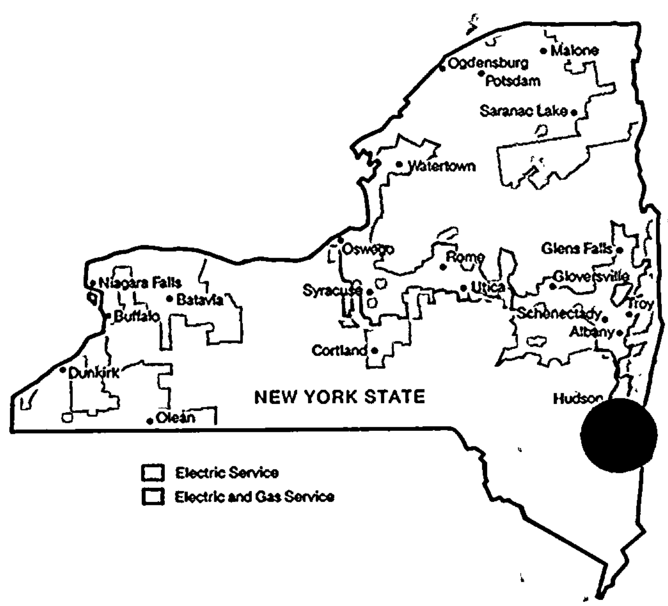
Serving Our Customers in Upstate New York

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 natural gas system provides service to over 490,000 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 builds and operates power production facilities.



Highlights

	1992	1991	%Change
Total operating revenues	$3,701,527,000	$3,382,518,000	9.4
Income available for common stockholders	$ 219,920,000	$ 202,958,000	8.4
Earnings per common share	$1.61	$1.49	8.1
Dividends per common share	$0.76	$0.32	137.5
Common shares outstanding (*average*)	136,570,000	136,100,000	.3
Utility plant (*gross*)	$9,642,262,000	$9,180,212,000	5.0
Construction work in progress	$ 587,437,000	$ 568,994,000	3.2
Gross additions to utility plant	$ 502,244,000	$ 522,474,000	(3.9)
Public kilowatt-hour sales	33,581,000,000	33,597,000,000	(.1)
Total kilowatt-hour sales	36,611,000,000	36,738,000,000	(.3)
Electric customers at end of year	1,543,000	1,538,000	.3
Electric peak load (*kilowatts*)	6,205,000	6,093,000	1.8
Natural gas sales (*dekatherms*)	79,195,000	71,729,000	10.4
Natural gas transported (*dekatherms*)	65,845,000	50,631,000	30.0
Gas customers at end of year	493,000	482,000	2.3
Maximum day gas deliveries (*dekatherms*)	905,872	852,404	6.3

THE 1992 REVENUE DOLLAR

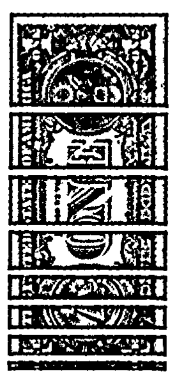
39¢ Residential customers

35¢ Commercial customers

17¢ Industrial customers

9¢ All others

AND WHERE IT WENT



26¢ Fuel for the production of electricity and electricity purchased

17¢ Income and other taxes

15¢ Wages, salaries, employee benefits

12¢ Other

8¢ Gas purchased

8¢ Interest – net

7¢ Depreciation

4¢ Dividends to stockholders

3¢ Retained in business

To Our Shareholders:

Niagara Mohawk made considerable progress in 1992, enhancing service performance and continuing to build financial strength. The year contained its share of challenges, but the process of change and improvement we initiated three years ago has firmly taken hold across the company, and results in many areas are beginning to improve.

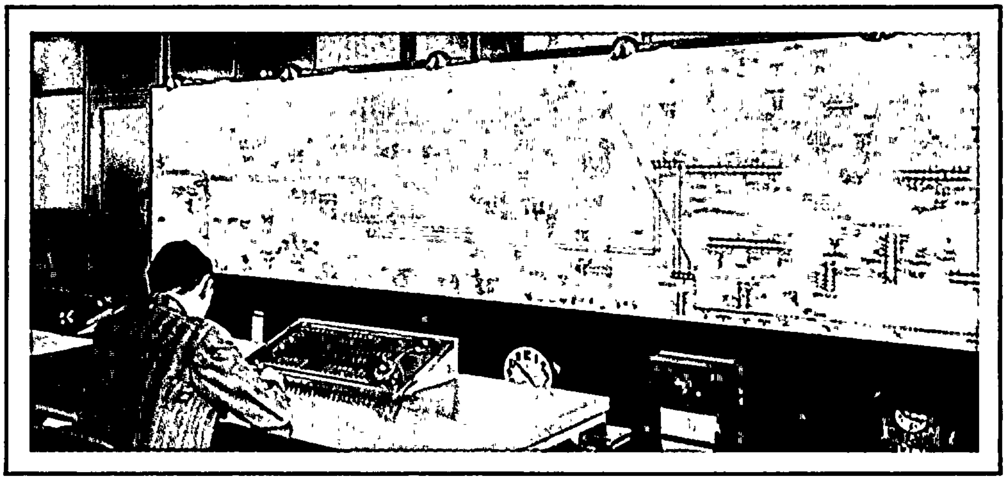
Earnings for 1992 were $219.9 million or $1.61 per share. This represents over 8 percent improvement compared to earnings of $1.49 in 1991.

The increase resulted from progress in a number of areas of our operations, but increases in base rates for electric and gas service, and our ability to earn financial incentives were very important contributing factors. Somewhat offsetting these gains has been the necessity to provide for a reduction in value of the oil and gas properties of Opinac, our Canadian subsidiary.

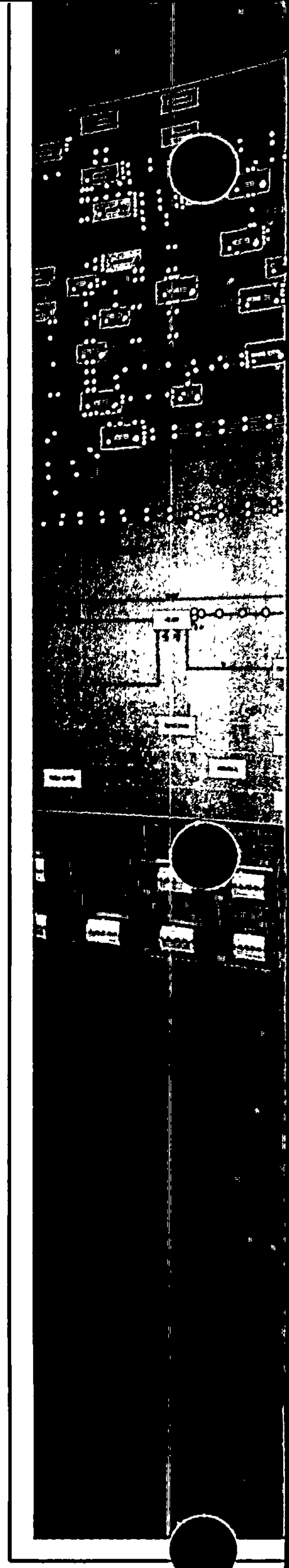
As gratifying as the increase is, our earnings for 1992 remained below our allowable rate of return on equity. We remain committed to the goal of earning the full return allowed in rates.

In 1992, our earnings included $26.8 million in special performance incentive awards known as MERIT. This raises our total merit earnings to $56.8 million since the Public Service Commission-approved program began in 1991. We are in the process of finalizing our report of accomplishments during 1992 while also concluding discussions with the PSC on goals for 1993 through 1995.

We achieved our goal of dividend growth in 1992, raising the quarterly dividend from $0.16 per share to $0.20 per share. Total return to stockholders in 1992 dividend plus price appreciation was 11.2 percent.



IN CONTROL — Above, an early power control center in Albany, and right, Vice Chairman William E. Davis, Chairman and CEO William J. Donlon and President John M. Endries pictured in front of Niagara Mohawk's modern power control facility near Syracuse.

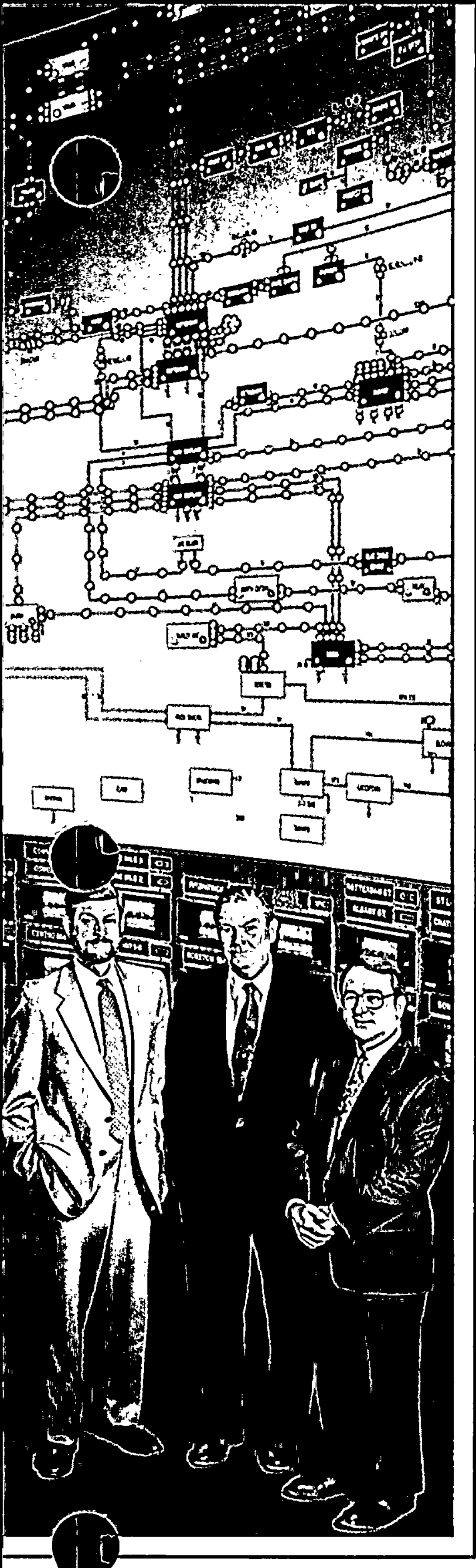


Increasing the dividend again in 1993 is a key goal of our board.

We also intend to issue additional common stock in 1993 and 1994 to strengthen our capitalization ratios in response to the increasing risk profile of our business. We will continue our aggressive debt refinancing program. Last year, most of the proceeds from more than $1 billion in transactions went to retire higher cost debt, resulting in annual savings of about $9 million.

In addition to our financial progress, 1992 saw numerous other achievements for our company, some of which will be highlighted in other sections of this annual report. I will touch briefly on several that were of greatest significance.

- We have made impressive strides in the environmental arena, and have begun to receive regional and national attention for our initiatives. A prime example is our land management program, especially the comprehensive Upper Hudson project that included a land transfer to New York State and which has been lauded by New York Gov. Mario Cuomo and others.



Also, we developed an extensive program for the remediation of waste sites left from the era when gas was manufactured from coal. And we are developing cost-effective and efficient ways to meet and, where practical, exceed The Clean Air Act Amendments' emission reduction targets.

Our research and development efforts with photovoltaic cells and wind power are attracting interest across the nation. Niagara Mohawk will continue to be an industry leader in environmental affairs for two reasons: it is the right thing to do, and it is good business.

• Advance planning and a vigorous marketing program enabled NMGas, Niagara Mohawk's natural gas Strategic Business Unit, to enjoy good results. NMGas increased the number of residential gas heat customers it serves by nearly 11,000 last year and increased total throughput by 22.7 million dekatherms. In 1992, a major Federal regulatory change further opened the natural gas industry to competition. The company is well positioned to take advantage of the change under its new business unit structure.

Other challenges in the near future, both for our gas and electricity business, are expected from the National Energy Policy Act of 1992, and from new environmental and tax requirements now under discussion.

• Last year, we spoke of the need to come to grips with the proliferation of Non-Utility Generators (NUGs) in our service territory, and the impact they are having on our customers' bills.

Early in 1992, we successfully sought repeal of the state law that granted a minimum price of six cents per kilowatt-hour, well above current avoided costs, to qualified NUGs. We also actively participated in the Public Service Commission proceeding that lowered the price for future contract negotiations with all NUGs.

Unfortunately, the Six-Cent Law repeal applies only to future NUG projects. We continue to take actions, from contract enforcement to project buyouts, to mitigate the impacts on customer bills caused by NUG contracts grandfathered by the repeal.

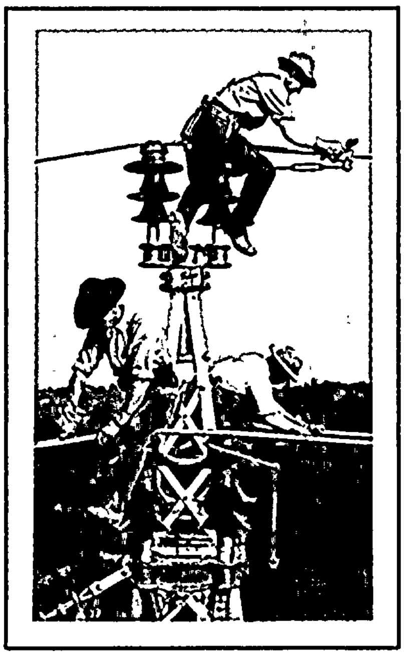
• We negotiated a rate increase that was approved in January by the PSC. The increase is necessary to meet expenses, including significant amounts for NUGs, environmental remediation efforts, demand-side management programs and amounts caused by changes in accounting for certain post-retirement costs that become effective this year. The agreement provided for a reduction in the allowed return on equity to 11.4 percent. We are actively participating in an important generic financing proceeding at the PSC which, among other things, is examining new and improved equity pricing methodologies that would provide competitive returns in both high and low interest situations.

Niagara Mohawk has a long tradition of being among the lowest-cost providers of energy services in New York and the Northeast. That is because we have spent decades developing a diverse fuel mix — a strategy that has served our shareholders and our customers well in good economic times and bad.

Our efforts to control internal costs, to develop new pricing strategies and to reduce the impact of NUG payments on our customers' bills are all geared toward one thing — being competitive. Quality service at reasonable prices is not only our hallmark, it is our lifeblood.

To build value for shareholders, we must provide value to our customers. By working hard to limit price increases we can reduce the risk of losing larger commercial and industrial customers to bypass or to relocation out of our service territory.

letter continued ...



There are a number of competitive challenges we must overcome if we are to achieve our corporate vision of becoming the most responsive and efficient energy services company in the Northeast, providing maximum value for customers, shareholders and employees. The depth of talent in Niagara Mohawk's work force and our commitment to continuous improvement make us confident we will succeed.

For example, our recent economic analysis of our Nine Mile Point Unit One nuclear station indicates the plant will likely provide a net benefit to our customers through its next fuel cycle, and, depending on future events, could provide benefits for the remaining 17 years of its license. The Board of Directors concurred with our decision to operate the plant at least through the end of the next fuel cycle, in early 1995.

The company will further evaluate all factors that affect the economics of Unit One. But it is clear that the plant's future depends on improved performance and cost control, without compromising safety.

In fact, cost control remains a priority across the company. Negotiations with the International Brotherhood of Electrical Workers in 1993 will include frank discussions of work practices, benefit costs and the need to remain competitive. A united effort by all is essential. We have also continued our efforts to insure the fair valuation of our utility property, and to seek real estate tax reductions where appropriate.

We have been evaluating overall employment levels, to ensure our human resources match our service requirements. For example the nuclear division has reduced staffing levels by approximately 500 positions since 1991, while improving performance.

Based on a study of non-nuclear employment completed in 1992, the company plans to reduce its work force during the next three years, primarily through attrition.

We have taken a number of other steps to control labor costs while providing employees with competitive wages, benefits and performance incentives. Our incentive management compensation program completed its second year in 1992, and we are pleased with the results it has stimulated.

Our flexible benefits program for management employees, as well as enhancements to savings plans for all employees, will improve these services for the people of Niagara Mohawk while helping the company to control expenses better.

Although this is the last annual report I will sign as Niagara Mohawk's chairman and chief executive officer, I will remain as a member of your Board of Directors.

I am very pleased to report that in November, the Board unanimously elected William E. Davis as vice chairman. He will succeed me as chairman and chief executive officer upon my retirement in April.

Bill Davis joined Niagara Mohawk in 1990 as vice president of corporate planning and was named senior vice president this past April. He joined us from the state's Energy Office, where he was executive deputy commissioner. His skills are outstanding. Bill has a strong strategic orientation and the broad expertise needed for balanced decision making.

He will value and enjoy, as have I since 1988, the effective operational oversight provided by company President Jack Endries.

Several other changes during 1992 enhanced our outstanding management team. One was the return of Jack R. Swartz to headquarters in the key position of vice president — Employee Relations. He had been vice president — Electric Customer Service, Eastern. We welcomed Nicholas J. Ashooh as vice president — Public Affairs and Corporate Communications, and Neil S. "Buzz" Carns as vice president — Nuclear Generation.

During my 45-year career with Niagara Mohawk I have witnessed many changes in the company and the utility industry. No changes have been more profound than those of the past few years. Niagara Mohawk has come a long way since the difficult days of the late 1980s. I am proud of the effort the people of this company have made.

There are significant issues still to be faced, and difficult decisions to be made. But I am confident that Niagara Mohawk will continue to move toward and ultimately achieve its vision of being the best.

William J. Donlon
Chairman of the Board and
Chief Executive Officer
February 22, 1993

Strategic Planning

In the last two annual reports, Niagara Mohawk has outlined its vision for the 1990s — to become the best energy services company in the Northeast — and described the process of reorganization and change that was the first stage in achieving the vision.

The reorganization is complete, with the Strategic Business Units and their Corporate Support Units in place. The process of change goes on, however, as Niagara Mohawk continually looks within to examine what it does and determine how to do it better.

Determining how to become the best requires a unified plan of action. Determing when a company has become the best requires an exacting method of measuring results.

Niagara Mohawk developed both during the past year.

The company's Corporate Strategic Plan is the culmination of many months of planning activities. It sets the foundation, and provides the direction, for the Strategic Business Units and Corporate Support Units to develop their own business plans and budgets. It clearly communicates those areas of strategic importance that will require the company's attention over the next several years.

The plan covers the years 1993 to 1995 — the period over which Niagara Mohawk intends to become the best. It sets goals and strategies based on four clear-cut objectives:

- To improve total returns to shareholders.
- To improve customer service quality.
- To improve the work environment for employees.
- To improve environmental performance.

The operating plans and budgets developed by the Strategic Business Units and Corporate Support Units must support those objectives and the numerous specific goals and strategies that flesh out the objectives.

To gauge its success in moving toward the objective, Niagara Mohawk has developed benchmarks measuring performance in seven specific areas against a peer group of 23 utilities.

To become the best energy services company in the Northeast, Niagara Mohawk must achieve a top-quartile ranking among these utilities in all seven areas. Over the next three years, the seven benchmarks will also help to identify performance gaps and determine how to close the gaps.

The seven benchmarks are:

- Total return to shareholders.
- Ratio of stock price to book value.
- Non-fuel operating and maintenance costs per megawatt-hour of electricity sales.
- Non-fuel operating and maintenance costs per dekatherm of gas deliveries.
- Customer complaints to the Public Service Commission.
- Lost workday case accident rate.
- Total Occupational Safety and Health Administration-recordable accident rate.

Niagara Mohawk's baseline for the seven areas is the 1990-91 time frame. The company was in the top quartile in only one area, third among 22 electric utilities in non-fuel operating and maintenance costs per kilowatt-hour of electricity.

Stringent cost control measures and implementation by the company's Electric Supply and Delivery SBU of the most aggressive substation preventive maintenance program in company history should help Niagara Mohawk to maintain and possibly better that high ranking. Final results for 1992 should be available in May.

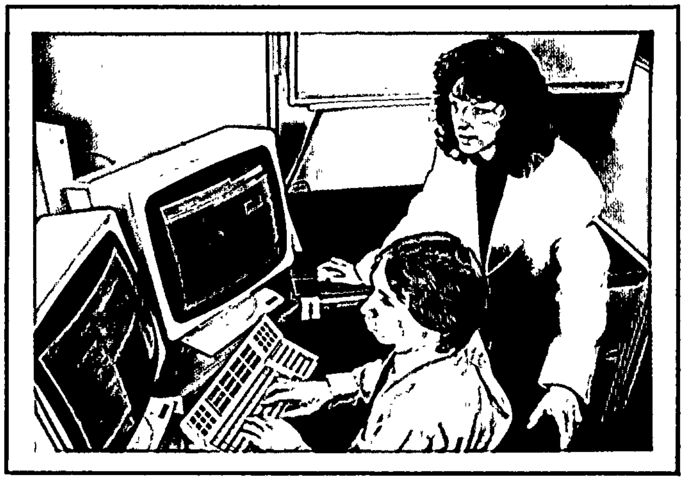
Niagara Mohawk ranked fourth among nine gas utilities in operating and maintenance costs during the baseline period.

The company was also fourth among nine New York State utilities in complaints by customers to the Public Service Commission. Niagara Mohawk's recorded complaints last year dropped below 1991 levels, which in turn were 28 percent below 1990 levels.

A number of specific programs, combined with an overall emphasis on customer service, helped to reduce complaints. Electric system reliability continued to improve, as measured by customer interruption duration and system interruption frequency.

Electric Supply & Delivery also implemented an advanced program that allows its System Power Control center to analyze conditions in power plants and on the transmission system more quickly, avoiding equipment damage and customer interruptions.

Two of the seven performance benchmarks measure safety, and in those, Niagara Mohawk was lagging near the bottom during the baseline period. That is changing quickly.



Niagara Mohawk's Human Resources CSU has initiated a new company-wide safety program that, for example, reduced the disabling injury rate in ES&D by more than 50 percent last year, and two thirds since 1990. In the high-exposure Fossil & Hydro operations, the rate has dropped to slightly above one injury per 100 employee-years worked. The Electric Customer Service SBU's safety performance has also improved beyond expectations.

The remaining two benchmarks, measuring financial performance, also pointed to the need for improvement during the 1990-91 period and it has indeed occurred in the total return to shareholders. However, our stock price market-to-book ratio lags at this point, and is a focal point for management.

Niagara Mohawk has also begun benchmarking in the SBU's. ES&D inaugurated a program to define the processes that create value for customers, and to measure performance of tasks against industry bests. Programs are being extended to the other SBU's as well.

Our organization at a glance ...

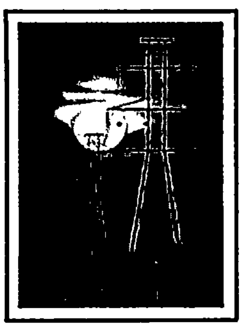
In 1990, Niagara Mohawk began to restructure its operations into four Strategic Business Units (SBUs): Electric Customer Service, Electric Supply and Delivery, Niagara Mohawk Gas and Nuclear. Each is a separate business accountable for its own results in support of overall corporate goals. Each has its own capability for such functions as planning, budgeting and labor relations, so that it can operate at a high level of independence.

The SBUs are largely autonomous. Only those functions that provide economies of scale, such as data processing, and those that require overall corporate policy and direction, such as strategic planning, employee benefits and external affairs, are still performed at the corporate level. These

Electric Customer Service —

Niagara Mohawk's largest business unit, with about 4,600 employees spread over the company's entire 24,000-square-mile service territory. This SBU provides the direct contact point for 1.5 million residential, commercial and industrial customers that used more than 36 billion kilowatt-hours of electricity last year.

Electric Customer Service is divided into eight operating regions. Its broad spectrum of customer contacts include new service connections, our innovative demand-side management programs, service tailored to fit the needs of large industrial users, billing, customer telephone contacts and meter reading.



Electric Supply & Delivery —

Develops, operates and maintains Niagara Mohawk's fossil and hydro generating facilities and its extensive electric transmission system, and administers the company's electric research and development programs.

Electric Supply and Delivery also is responsible for buying and selling wholesale power and managing nearly 1,600 megawatts of installed non-utility generating capacity.

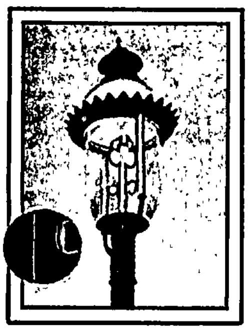
The company's 4,200 megawatts of fossil and hydro generating capacity is also managed by ES&D. Niagara Mohawk operates 74 hydro stations, more than any other utility in the country.

The Power Delivery Department of ES&D controls more than 900 electric substations and about 9,200 circuit miles of electric transmission lines.

functions are divided among three Corporate Support Units: Finance and Corporate Services, Legal and Corporate Relations and Human Resources.

With the restructuring completed during 1991, last year was the first full year of operation for the four SBUs, and it was a successful one. The SBU structure supports our commitment to customer service by sharpening our focus on the differing needs of customers served by the SBUs. It also furthers our effort to give employees greater responsibility and authority to make the decisions necessary to meet customer needs.

Below are brief descriptions of the four SBUs. Their major accomplishments and future plans are described in the following pages.



NMGas —

Serves nearly a half-million residential, commercial, industrial and transportation customers in a 4,500-square-mile service territory and maintains 7,000 miles of transmission and distribution mains.

NMGas provides every service related to natural gas supply and delivery including purchasing, transportation, marketing, delivery and service to individual customers.

Nuclear —

Operates the two Nine Mile Point nuclear power plants, located near Oswego, N.Y., on the shores of Lake Ontario. Nine Mile One is a 610-megawatt plant owned by the company. Niagara Mohawk owns 41 percent of 1,080-megawatt Nine Mile Two and operates the plant. Four other New York utilities own smaller percentages.

Competition

Niagara Mohawk, like every other utility in the country, is now in the midst of an era of stiff — and growing — competition in both its electric and gas businesses.

Competition from non-utility generators (NUGs) has eliminated the company's natural monopoly in electricity generation but has not lowered prices for customers. Just the opposite.

Federal law requires that Niagara Mohawk buy all the power offered by qualifying NUGs. In addition, a state statute commonly known as the Six-Cent Law has, until recently, guaranteed certain NUGs a minimum payment per kilowatt-hour which is twice as high as the present open-market wholesale price.

As a result, Niagara Mohawk has been forced to take too much NUG supply at too high a price. The company estimates overpayments to NUGs at $268 million in 1992, or about 8 percent extra on our customers' bills.

In response, Niagara Mohawk formalized an action plan early in 1992, initially centered on convincing the State Legislature to repeal the Six-Cent Law.

Within months, the Six-Cent Law was repealed, but only as it applied to NUGs without contracts. In addition to those already operating, the 768 megawatts of NUG projects under construction and the 1,353 megawatts not yet started but with existing contracts were "grandfathered" in.

Niagara Mohawk's other actions to reduce NUG impacts on customers during 1992 have included active participation in the state Public Service Commission's 1992 Long-Run Avoided Cost (LRAC) case, which sets the current and future prices for NUGs that do not qualify for the six-cent minimum. In deciding the case, the PSC reduced 1992 LRACs to about half the 1990 level.

Niagara Mohawk also has intensified its monitoring of NUG compliance with contracts. It has terminated the contracts of a number of NUGs that have not been meeting contract terms. Other contracts have been renegotiated, or bought out when that proved economic.

Niagara Mohawk has filed a petition with the PSC requesting that it be allowed to verify whether certain NUGs are maintaining "Qualifying Facility" (QF) status under the federal Public Utility Regulatory Policies Act. The Act contains operating and efficiency standards and an ownership test which a NUG must satisfy before a NUG becomes a QF and a utility is required to buy power from it at a price set according to the LRAC. The company wants to be sure that NUGs continue to meet those criteria.

In addition, Niagara Mohawk asked the PSC for permission to curtail NUG output, rather than its own lower-cost capacity, during times of low demand. The company also petitioned the PSC to require certain NUGs to provide firm security to ensure that they will return to Niagara Mohawk customers the overpayments they receive in the early years of operation, as the NUGs' contracts require. Action on these petitions is expected in mid-1993.

POWER OF CHOICE — The Stora Papyrus plant in Newton Falls, N.Y., at right, is typical of the new options available to industrial electricity customers. It runs a hydro dam to produce one-third of its power, and Niagara Mohawk supplies the other two-thirds. Stora made the paper for this report, using recycled waste paper from Niagara Mohawk. Shown at far right is a historic view of the electric utility business, a turn-of-the-century street light being serviced by a Buffalo Niagara Company employee. The power came from the first alternating current line in the U.S.

The company estimates that its efforts have reduced potential NUG overpayments by more than $650 million over the next 30 years. As a result of actions taken thus far, and reductions in other billing factors, the projected rise in customer bills is slowing, and actions still under way will lessen upward pressure on rates still further.

Despite the higher costs from NUGs in its wholesale electric business, Niagara Mohawk sees potential opportunities in competition.

Last year's major federal energy legislation will further open the electric utility industry to competition. Repeal of the Public Utility Holding Company Act may allow Niagara Mohawk and its subsidiary, HYDRA-CO, greater latitude to pursue unregulated projects if they make sense for customers and shareholders.

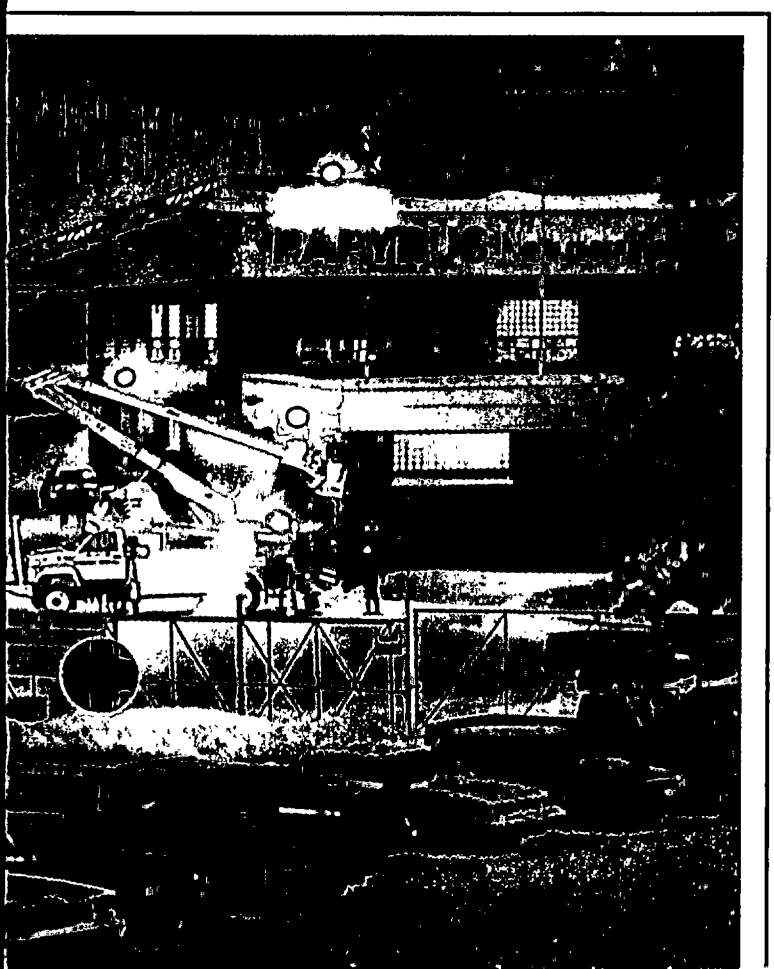
Another provision opens access to utility transmission systems, but whether utilities will receive a fair return for that access remains in doubt. Depending on the resolution of this issue, Niagara Mohawk could realize significant additional revenue for transmitting power from the many NUGs in its service territory to other utilities. In addition, gas-fired NUGs are potential large-volume customers for NMGas.

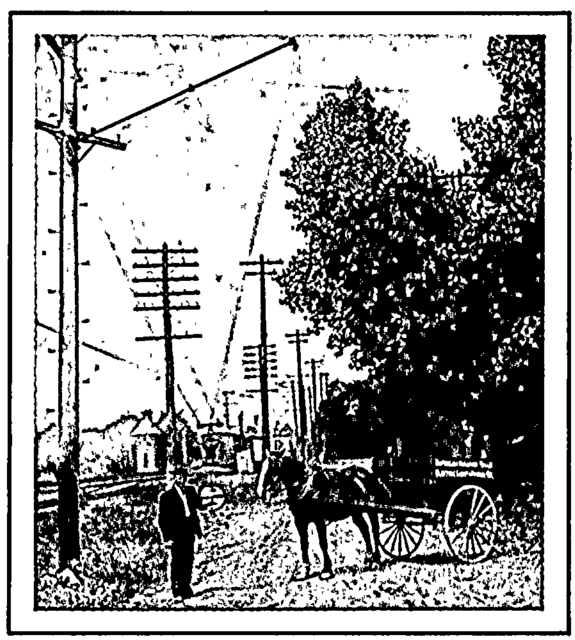
Natural Gas Market

Substantial deregulation of the nation's interstate natural pipelines has made the supply side of the gas business more competitive and challenging. Overall, deregulation has driven prices down and created the opportunity for Niagara Mohawk to tailor services and rates more closely to customer needs.

In 1992, the Federal Energy Regulatory Commission issued Order 636, which is designed to complete the "unbundling" of the nation's natural gas pipeline services. Seven years earlier, another FERC order had allowed Niagara Mohawk's 650 largest customers to buy gas directly from producers, with the company providing transportation. In 1991, Niagara Mohawk had successfully negotiated an agreement that partially unbundled service with its major pipeline supplier, giving the company direct access to firm gas supplies, storage and pipeline transportation services. Order 636 now grants complete access to these services for distribution companies such as Niagara Mohawk.

Over the past several years, NMGas has increased its diversity of supply, improved the infrastructure, stepped up marketing efforts and made great strides in providing superior customer service. Those strategies leave the company well positioned to take advantage of the opportunities offered by the new competition in the gas market. NMGas also will be focusing on intensified competition from fuel oil, electricity, other gas companies and unregulated energy service companies.





Environment

Land Management

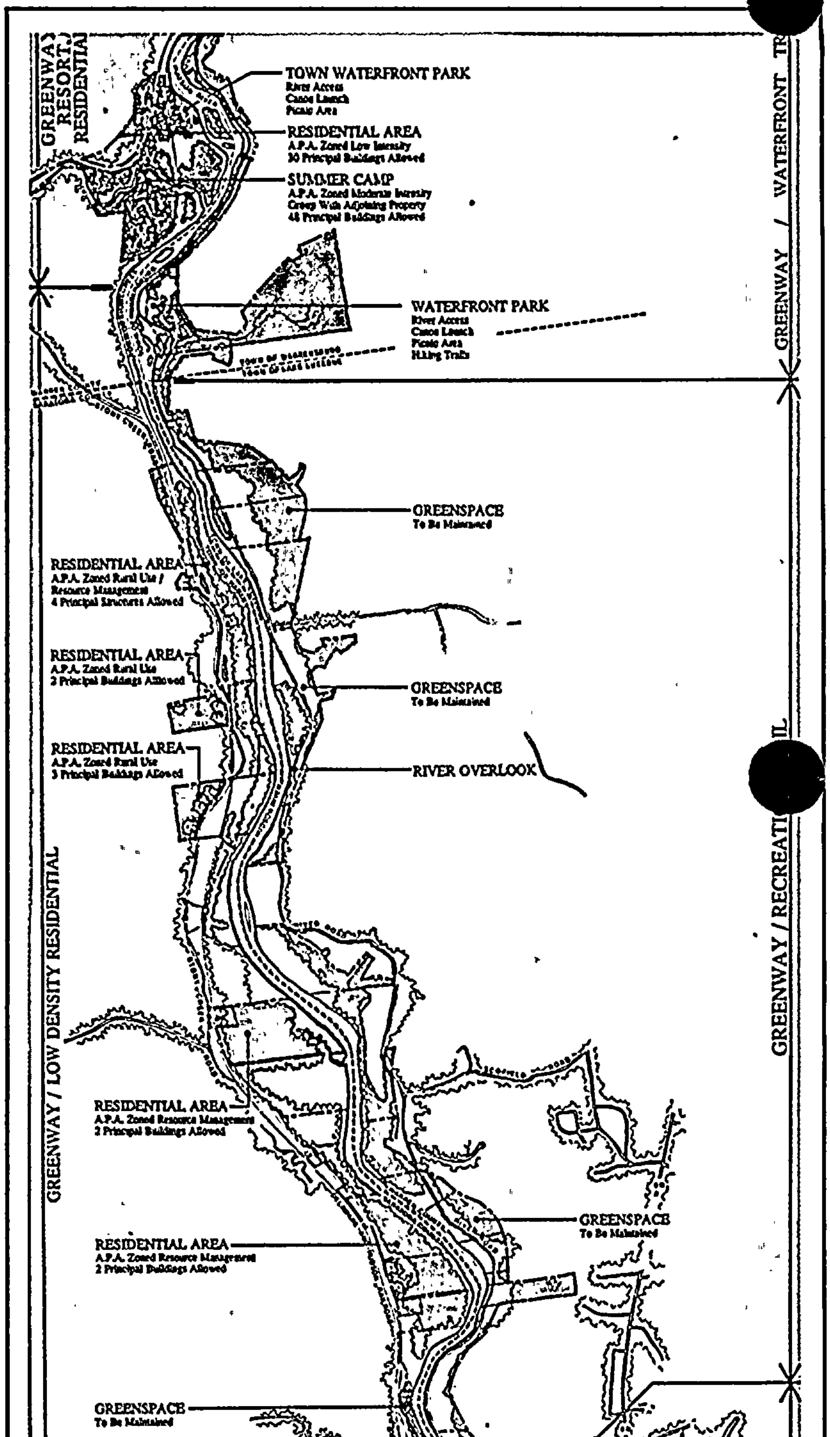
As part of its environmental policy, Niagara Mohawk has taken a fresh look at its extensive landholdings.

Some land is no longer needed for energy production, and Niagara Mohawk has developed a comprehensive land management policy to find the highest and best use for each parcel, achieving the proper balance between environmental preservation and the region's economic needs.

The first fruits of that policy came during mid-1992, when the company announced its plan for 2,400 acres of its land along the upper Hudson River in the Adirondack Park.

Niagara Mohawk developed the plan, called the Upper Hudson Greenway Project, in cooperation with state government, community interests and environmental groups. As part of the plan, the company conveyed about 1,200 acres along 16 miles of shoreline to the Conservation Fund for ultimate inclusion in the Adirondack Forest Preserve.

The plan drew praise from Gov. Cuomo at an Albany ceremony announcing the land conveyance to the state, and earned Niagara Mohawk awards from the Adirondack Council and the Adirondack Park Centennial Committee.



Niagara Mohawk serves one of the most beautiful and, in some ways, environmentally fragile regions of the Northeast. As a landowner and caretaker in scenic forests and wetlands, abounding in pristine lakes and rivers, the company always has been aware of its responsibility for environmental preservation.

In recent years, environmental challenges have multiplied. At the same time our customers' awareness of environmental issues has grown.

In response, Niagara Mohawk adopted a forward-looking "beyond compliance" environmental policy in 1991. Last year, the company took a number of actions based on the policy that place Niagara Mohawk in the forefront of corporate environmentalism.

Among these actions are the training of all employees in environmental awareness, regular environmental auditing of the company's operations to assure compliance, adoption of criteria for measuring corporate environmental performance, and incorporation of the environmental policy and specific targets in business plans. The company believes it is in the best interests of customers, shareholders and employees for Niagara Mohawk to be a leader in addressing environmental concerns.

Niagara Mohawk's approach to environmental protection includes research and development of efficient and renewable energy technologies, and energy conservation (see separate stories).

Nearly half of the company's electricity is produced using low- or zero-emitting sources such as hydroelectric, nuclear, and natural gas sources which have relatively low environmental impact. At the oil- and coal-fired plants that make up the remainder, Niagara Mohawk has substantially reduced emissions over the past two decades.

The Clean Air Act of 1990 will require still lower emission levels and Niagara Mohawk in 1992 formulated strategy to meet Phase I requirements. To achieve compliance, Niagara Mohawk will implement a combination of alternatives that include: fuel switching, lower sulfur coal and gas co-firing, installation of low nitrogen oxide burners on coal units and fine tuning boilers and other steps. Phase I compliance is expected to require capital investment of about $90 million. Phase II of the Act is scheduled to go into effect by the year 2000. Specific requirements for this phase have not yet been determined.

During the year, the company became one of the first utilities in the United States to confront the problem of greenhouse warming. Despite the current scientific debate over the nature and extent of warming, Niagara Mohawk thinks the impacts projected by proponents of the greenhouse warming theory are so severe that action should not be delayed.

Niagara Mohawk's Greenhouse Warming Action Program has a goal of reducing company carbon dioxide emissions by almost twice as much as current federal government goals for the year 2000.

The company also will take actions to reduce emissions of other greenhouse gases such as chlorofluorocarbons. The actions in the plan will use low-cost, currently available technologies and will be economically justifiable in their own right.

Greenhouse warming was a major topic at last June's Rio de Janeiro Earth Summit, along with discussions of how to maintain the diversity of life on earth, and how to accomplish environmental goals while sustaining the global economy. In December, Niagara Mohawk became one of first corporations in the country to begin applying the lessons of Rio. The company, along with the State University of New York and the state Department of Environmental Conservation, co-sponsored "Environmental Summit '92, Messages from Rio, Directions for New York."

For two days, a distinguished group, including Governor Cuomo and representatives of business, academia, government and the environmental community, planned how to translate the agreements of the Rio conference into practical programs to benefit the people of New York state.

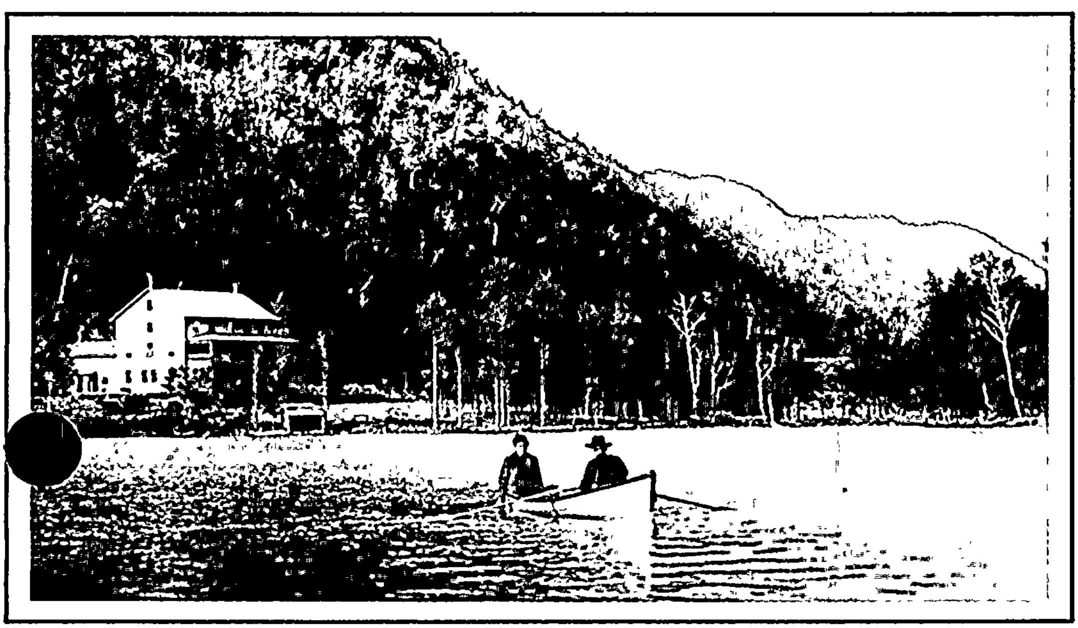
The company also is a leader in waste recycling. Niagara Mohawk's Investment Recovery Center, staffed almost exclusively by disabled workers, more than pays for itself. The center recycles more than 2 million pounds of paper a year, and is one of the first utility-operated recycling programs in the country to process scrap wire into nuggets, which command a higher market price.

While most of Niagara Mohawk's environmental initiatives look to the future, some of its environmental liabilities are a legacy of the past. The company's predecessors operated a number of sites where gas was made from coal to light street lamps and provide heat in the 19th century. Most of these manufactured gas plants shut down long before Niagara Mohawk came into existence, but many left a residue that must be cleaned up.

In December, Niagara Mohawk signed two separate agreements with the state Department of Environmental Conservation to study and, where necessary, clean up 22 such sites. Niagara Mohawk already has a clean-up project under way at Harbor Point in Utica which will pilot research and development remediation technologies. The company estimates that the site remediation program will take more than 10 years.

The company also has been successful in finding uses for fly ash, a by-product of burning coal and fuel oil to produce electricity. Disposal in landfills has been costly and environmentally sensitive, but Niagara Mohawk's Fossil Generation and Fuel Supply personnel have worked to find uses for fly ash in, for example, building foundations and roads, and as a component for roofing shingles. As a direct result of their efforts, last year the state Department of Environmental Conservation granted approval for such uses.

In 1992, about 12 percent, or 40,000 tons, of total ash was diverted from landfills to approved use, lowering landfill costs by $400,000 and generating more than $130,000 in gross revenues. Efforts will expand in the coming year.



Noted photographer B.R. Stoddard captured this view of boaters enjoying the tranquility of Edmonds Pond in the Adirondacks early in the century.

Demand-Side Management

Niagara Mohawk's Demand-Side Management (DSM) program links three of the company's main aims: customer service, energy efficiency and environmental protection.

The three-year-old DSM program puts Niagara Mohawk in partnership with its customers to improve their energy efficiency. The program is part of the company's Integrated Electric Resource Plan, a detailed study of the most economical way to meet each additional increment of future customer electricity demand.

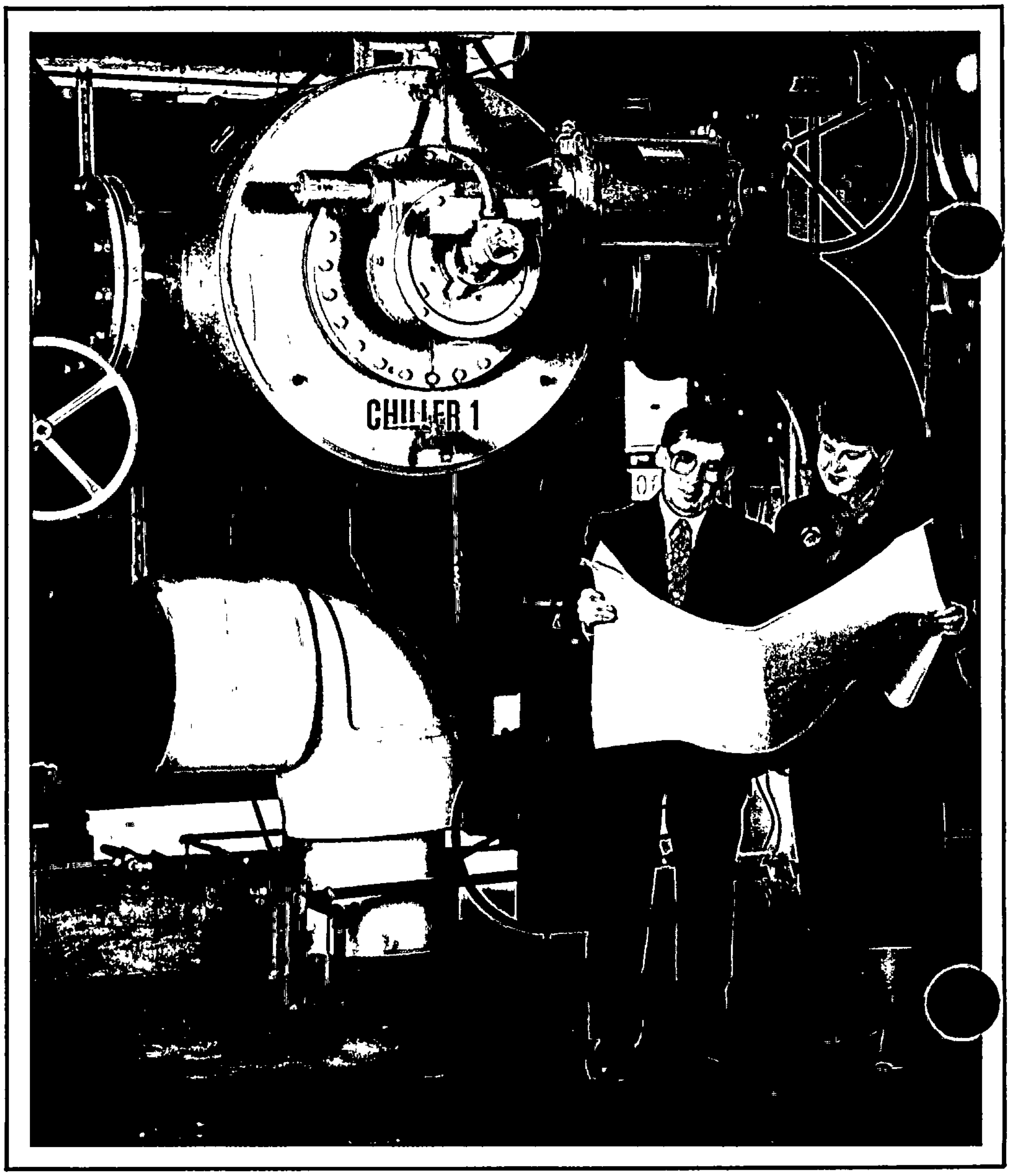
In many cases, managing demand can be less expensive than adding new supply. Long-range plans call for DSM to contribute as much as 400 megawatts, or 25 percent, of new capacity needed over the next two decades.

Niagara Mohawk's 16 company-sponsored and 6 bidder-sponsored DSM programs provide rebates and incentives to customers for taking energy conservation measures. This is a cost to the customer to save a kilowatt-hour, but it is less than the cost of generating the same kilowatt-hour.

Niagara Mohawk is compensated for DSM program costs and the lost profit resulting from usage reduction based on reduction goals and cost-effective program implementation. In 1992, the company exceeded its goal of 244,000 megawatt-hour reductions by more than 20 percent, based on preliminary figures.

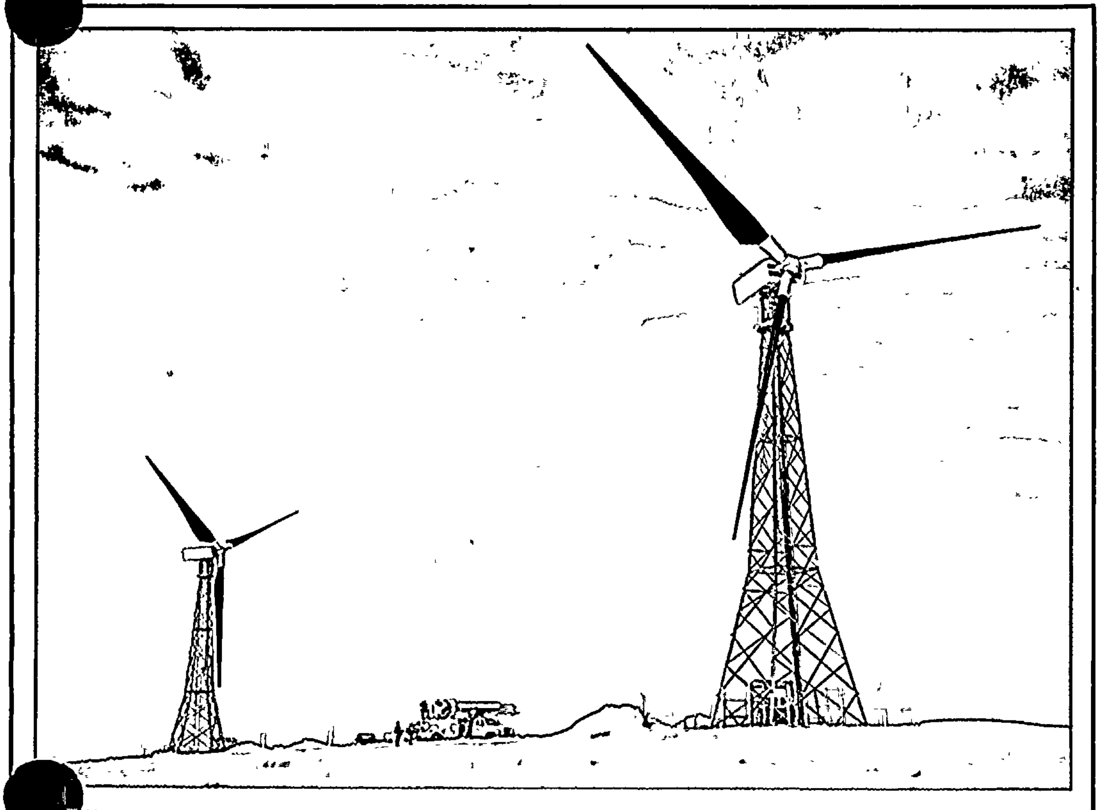
The industrial and commercial DSM programs have been so successful in promoting energy-efficient technologies and accelerating changes in the marketplace, that the high level of rebates and incentives is no longer necessary.

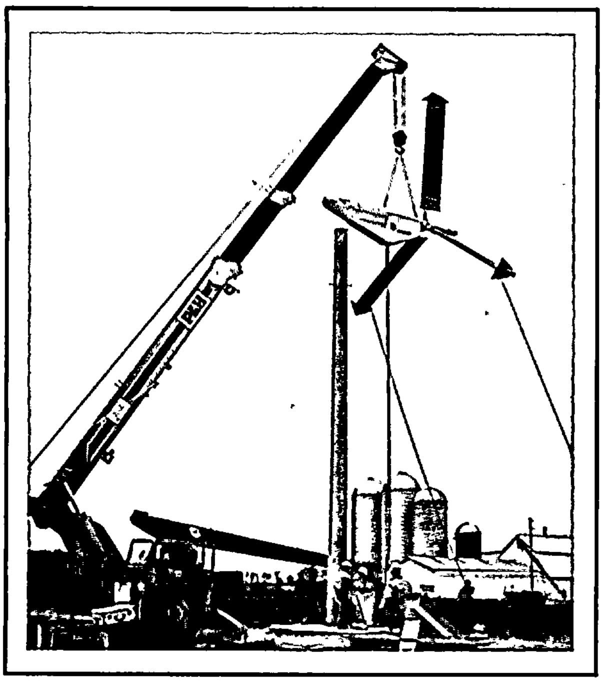
The company's 1993 program will be adjusted to allow pricing and other market forces to play a larger role.



DEMAND FOR SAVINGS — Linda Heim, a consumer relations representative, and Claude Rounds, vice president of plant management for Albany Medical Center, discuss Niagara Mohawk's Demand Side Management plan for the center. The project, one of the largest to be sponsored by a utility in the country, will save the Center $1.1 million per year in energy costs, a 35 percent reduction.

Research & Development





TESTING THE WIND — Niagara Mohawk has known of ...power's potential for some time, as shown in the ... photo of a 15-kilowatt turbine erected in 1977 in ...Lawrence County. At top, the company's two 360-kilowatt wind turbines, erected in 1992 near Watertown, demonstrate the advancement of the technology.

Niagara Mohawk has a significant research and development effort focused on developing the clean, renewable energy sources of the future. In September, the company installed two 360-kilowatt wind turbines on 80-foot towers near Watertown, N.Y.

The three-year project is the first of its kind in the Northeast and will determine whether the gusty north country winds can develop into an economical, reliable source of electricity. The advanced, variable speed turbines are products of U.S. Windpower, a participant in the project. Also joining Niagara Mohawk in the project are the Electric Power Research Institute and Pacific Gas & Electric Co.

Another Niagara Mohawk program, exploring the use of solar energy at a state office building near Albany, has been named by the U.S. Department of Energy as a winner of its 1992 "Innovative Energy Award."

The company installed 70 solar photovoltaic panels on the roof of the state Division of Military and Naval Affairs building in 1990. The demonstration project has been so successful that it has been extended by two years and expanded to include testing a battery storage system in combination with the solar array.

Niagara Mohawk is also testing a fleet of seven electric-powered cargo vans as part of a nationwide, three-year project aimed at commercializing clean electric vehicle technology.

The "G-Van" is designed for urban use, using a General Motors body, a special propulsion drive train and 36 lead-acid batteries. It has a top speed of 52 mph and can travel 60 miles between charges. Its makers hope the vehicle can be on the market within three or four years.

Natural Gas

Niagara Mohawk Gas, the company's natural gas Strategic Business Unit, had an outstanding year in 1992, increasing its total natural gas throughput 44.4 percent over 1991 to 79.2 million dekatherms. New business from cogeneration projects accounted for much of the increase.

NMGas continued its residential marketing push, picking up about 11,000 residential heating customers, some of whom added heating to their previous service, and many others who were new hook-ups. NMGas also completed its merger with Syracuse Suburban Gas. The $6 million transaction added 4,600 more customers and filled in a gap in the company's service territory and distribution system.

During the year, NMGas started its Target Account Program, aimed at providing increased value to industrial customers. NMGas made individual contact with 450 large customers and held quarterly group meetings, technical seminars and other events.

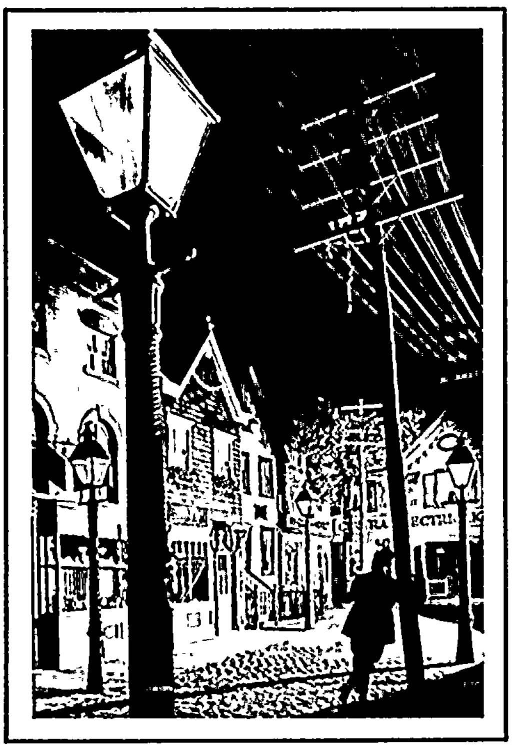
The SBU's focus on personal service, advertising and promotions increased public awareness of the advantages of natural gas during 1992.

The coming year is expected to see a strong market for natural gas nationally, and NMGas will concentrate on identifying growth trends and taking advantage of them. The company's goals include 13,000 new residential customers.

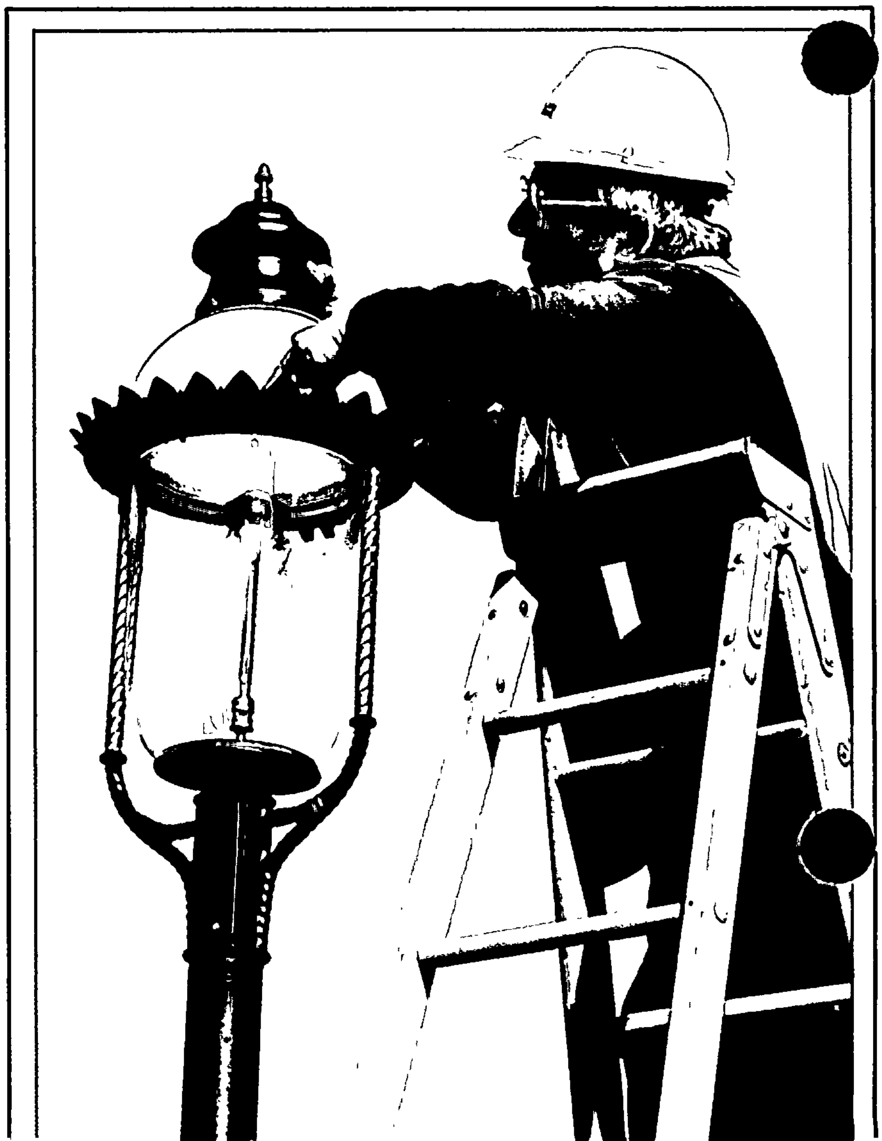
NMGas is developing a Gas Efficiency Plan, requested from all utilities by the state Public Service Commission by April 1. The plan will emphasize the flexibility and diversity of supply, customer service and operational efficiency programs that NMGas has developed in response to the intense competition in the natural gas industry. It also will outline some of the future programs NMGas will offer to assist customers in managing their demand for gas, much as Integrated Resource Plans for electricity have made use of demand-side management.

NMGas also will participate in the first installation of a public vehicular natural gas refueling station in the service territory, in partnership with Hess Oil. The station will open in Albany in mid-April. Two more are planned, one each for Albany and Syracuse, with a completion goal of late this year.

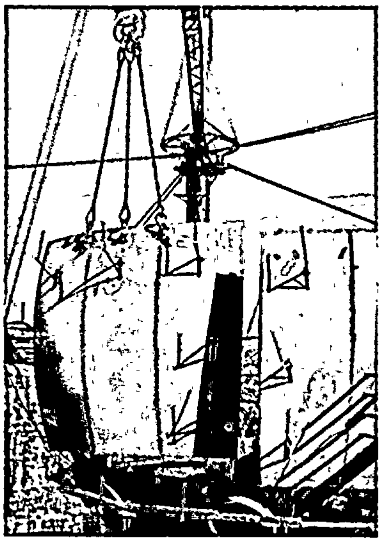
The company also has supported demonstrations of natural gas vehicles in the Syracuse school system and regional bus system, in addition to testing natural gas fleet vehicles in its own operations and with others.



WHAT'S OLD IS NEW — Although gas lights faded out in Niagara Mohawk's service territory in the 1920s, the company helped to recreate an 1892 gas-lit street scene for the 1939 New York World's Fair, top. At right, after an absence of more than 70 years, gas street lighting reappeared as NMGas began service last May for Bellevue Estates in Syracuse.



Nuclear



At left, a portion of the containment structure for the Nine Mile Point Unit 1 nuclear facility is lowered into place in 1965.

One of Niagara Mohawk's most important tools for cutting costs and improving efficiency is its nuclear materials testing laboratory.

The lab qualifies parts for the plant as "nuclear grade."

Nuclear utilities pay a premium for parts that meet specifications. The materials lab has two major roles in cost-cutting: making sure Niagara Mohawk gets what it paid for, and finding off-the-shelf parts for a fraction of the cost of special-ordered components.

For instance, according to lab director Grant Pierce (above left), the company ordered a valve supposedly made of stainless steel, but the lab found it was nickel-coated brass, which is not nuclear grade.

A special-ordered nuclear grade transistor can cost as much as $2,000, but the lab found transistors at a local electronics store that met specifications—for 30 cents each. Testing and certifying the transistors costs $40, but the company still realized considerable savings.

Niagara Mohawk's Nine Mile Point Units One and Two nuclear power plants both finished 1992 on high notes, operating at full power. Nine Mile One set monthly production records in November and December, and both plants set quarterly production records in the last three months of 1992.

The company's Nuclear SBU spent the year streamlining and strengthening its operations. In August, the company received two "excellent" and five "good" marks from the Nuclear Regulatory Commission in an evaluation of seven categories critical to plant safety and performance.

Executive Vice President – Nuclear, B. Ralph Sylvia, said he is pleased with the report, but ..., "We are not satisfied with only being considered a good nuclear operation and will remain focused on ... our vision of becoming an industry leader."

Management systems improvements included initiation of a comprehensive procedure rewriting process, and development of a problem identification and resolution program that empowers each employee to address plant concerns.

The nuclear unit continued its industry-wide search for top talent, bringing in a vice president and other executives from other utilities and internally identifying innovative and skilled managers as candidates for further training and promotion.

At the same time, the company continued its "right-sizing" efforts, which it began by comparing Niagara Mohawk nuclear operations to the best operations in the industry to determine the right number of people required to be a top-flight facility. Steps toward the ultimate "right-sizing" goal of no more than 1,600 employees will be taken during 1993. By 1994 the SBU will have reduced more than 900 positions from 1990 levels.

For the third straight year, the nuclear budget was reduced, and the SBU improved operations under the tighter budget. Expenditures were 30 percent below the 1990 budget.

...th Nine Mile Point units will undergo refueling during 1993. Nine Mile Point One began a refueling outage in February. ...ile Point Two will begin its third refueling in the fall.

Outreach & Education

SERVING A NEED — Above, Niagara Mohawk employees demonstrate cooking with electric and gas appliances at a New York State Fair during the '60s; and, top, a Consumer Advocate explains company services to customers in a home visit.

Niagara Mohawk strengthened its emphasis on customer service in 1992 identifying, evaluating and responding to customer energy-related needs.

The company's Outreach & Education (O&E) program is a vehicle for two-way communication with customers. Research is used to identify and analyze customer needs and assess the impact on customers of new or revised programs, policies, procedures and services.

For instance, in 1992 the company conducted focus groups and discovered two levels of interest — those interested only in the amount of their bills, and those interested in everything the company does.

The O&E program takes this information and coordinates production and distribution of informational materials tailored to meet different customer needs, from senior citizens to those who might need help paying their bills. The materials are keyed to different levels of interest and literacy.

The materials provide customers with beneficial information about their rights and responsibilities and how to obtain full and fair resolution of their problems and complaints. Panels, roundtables and other gatherings are sponsored by Niagara Mohawk to provide feedback from customers.

The whole aim of the effort, which also includes training for Niagara Mohawk customer contact personnel to improve their communications skills, is to make Niagara Mohawk more "user friendly" for customers.

Economic Development

Niagara Mohawk continued efforts to improve economic conditions within its service territory during 1992.

The company's Economic Development program is aimed in part at bringing new business into upstate New York. The company plans to spend more than $800,000 during 1993 on marketing efforts promoting upstate New York as a great place to do business. As of the end of 1992, Niagara Mohawk's Department of Economic Development is working with 170 Canadian and 80 domestic companies who have indicated interest in locating in the company's service territory as a result of past marketing programs.

Late in 1992, Niagara Mohawk played a lead role in organizing the "Partnership for a New, New York," a consortium of the state's energy and telecommunications utilities that will conduct a five-year effort, in cooperation with state government, to attract key industries and markets.

Subsidiaries

HYDRA-CO Enterprises, Inc., Niagara Mohawk's wholly-owned subsidiary formed to develop, own and operate independent power projects, entered its second decade of operation by reaching a milestone on a major domestic project and by expanding into the international market.

HYDRA-CO closed construction financing for a $262 million, 237-megawatt natural gas-fueled cogeneration plant in Lakewood, N.J.

A HYDRA-CO partnership was recently selected to negotiate final contracts on a 60-megawatt diesel power station in Kingston, Jamaica. The company is working on another project in Jamaica, and one in Canada.

HYDRA-CO now has 24 plants in operation or under construction, with a capacity of about 300 megawatts under equity ownership. The plants use a variety of technologies powered by diverse energy sources, including water, wood, coal, wind and natural gas.

The company's diversity reflects its judgment of what it takes to be a long-term developer, investor and operator in the independent power market.

Niagara Mohawk's Canadian subsidiary, Opinac Energy Corp., faced continuing problems in 1992 largely due to volatile crude oil and natural gas prices, coupled with a significant reduction in its estimated reserves of natural gas. As a consequence of the difficulties encountered, staff and management changes were made and capital expenses were restricted. During 1992, Opinac reassessed its strategies and direction, and is now positioned to grow through internal means or by way of external financing.

Canadian Niagara Power Ltd., Opinac's electric division, celebrated its 100th anniversary of operation at ceremonies in June. Its centenary year, like those before, was marked by good performance.

MUTUAL GAINS — Management and union representatives engage in a Mutual Gains Bargaining session, under the direction of facilitator Bernard L. Flaherty, standing, of the New York State College of Industrial and Labor Relations, Cornell University. The process is designed to produce better bargaining solutions and improve relationships between the parties. Seated, left to right, are Michael P. Ranalli, senior vice president–Electric Supply and Delivery; Raymond A. Vallilee, acting chairman, System Council U-11; Jack R. Swartz, vice president–Employee Relations; Charles A. Borell, president, Local Union 1484; and John W. Powers, senior vice president–Finance & Corporate Services.

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

Overview of 1992

Earnings for 1992 were $219.9 million or $1.61 per share versus $203.0 million or $1.49 per share in 1991. Factors contributing to the increase in earnings in 1992 as compared to 1991 include rate increases for gas and electric customers effective July 1, 1991 and July 1, 1992, decreased levels of nuclear operating and maintenance expenditures and cost management of non-nuclear expenses relative to amounts provided in rates, offset by oil and gas writeoffs. The Company's return on common equity in 1992 was 10.1%, as compared to an allowed return on utility operations of 12.3%. The earnings deficiency was caused by several key factors, including earnings of subsidiaries at a rate below the Company's authorized return on equity for regulated operations and spending for operational activities in an amount that exceeded the amount assumed in setting rates, offset by incentive equity returns for MERIT and DSM programs, and the Company's share of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2) proceeds of litigation relating to its construction. These and other factors are discussed in more detail under "Results of Operations." Through continuing self-assessment and financial and operational benchmarking, the Company's Strategic Business Units (SBUs) are addressing these and other issues that create earnings deficiencies as well as considering opportunities for earnings enhancements. Non-cash earnings in 1992 were $35.2 million, representing 16.0% of total earnings.

Dividends per common share increased to an annual rate of $.80 from $.64 during 1992, consistent with the Board of Directors' long-term financial goals for the Company.

The Company's capital structure at December 31, 1992 was 56.4% long-term debt, 7.4% preferred stock and 36.2% common equity. In early 1992 the Company began issuing new shares of common stock under the Dividend Reinvestment and Employee Stock Plans, and it now anticipates a public issuance of approximately 5 million shares in 1993. Such efforts are intended to continue improvement in the Company's capital structure. Market value and book value of common stock at December 31, 1992, were $19.13 and $16.33 per share, respectively; a market to book ratio of 117% versus a 115% ratio at December 31, 1991. The ratio of earnings to fixed charges for 1992 was 2.24, up from 2.09 in 1991.

Expenditures for construction in 1992, including nuclear fuel, related AFC, overheads capitalized and capitalized leases were $502.2 million and were primarily funded through internal sources. Construction expenditures had been forecast to be $513 million in 1992. The reduction in spending reflects emphasis on cost management by the SBUs. The 1993 construction estimate is $525 million of which 90% is expected to be funded from internal sources.

During 1992, the Company raised approximately $944.6 million from external sources, consisting of $835.0 million of debt (of which $794.8 million was used to refinance debt), $19.5 of common stock and a net increase in short-term debt of $90.1 million. The Company took advantage of low interest rates by implementing a refinancing program for approximately 23% of its outstanding debt, lowering its embedded cost of debt from 8.4% to 7.7%. The Company expects to require approximately $631 million of external financing in 1993, of which $438 million represents scheduled and optional refinancings.

There were several key developments during 1992 that demonstrate progress in the Company's continuing self-assessment program, as well as challenges for the future, including repeal of New York State's "6-cent law" for non-utility generator (NUG) contracts, an update of the Company's economic study of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) which indicated that continued operation of Unit 1 was economical at least for the next fuel cycle, issuance by the Federal Energy Regulatory Commission (FERC) of rules that could expand opportunities for the Company's gas business and passage of the Energy Policy Act of 1992 to repeal certain limiting regulations of the Public Utility Holding Company Act of 1935 and expand to others access to utility transmission facilities, including the Company's. These developments will continue to challenge the Company in 1993 and beyond.

Progress Towards Corporate Vision

The Company's Vision is to become the most responsive and efficient energy services company in the Northeast to achieve maximum value for customers, shareholders and employees. Progress towards that Vision began with the self-assessment process in 1989 and now forms the basis for many of the new initiatives recently undertaken by the Company.

A significant result of self-assessment and the drive towards the Vision is a change in focus in the ratesetting process, from base rate increases to customer bill impacts. The Company is keenly aware that changes in the utility industry and the regulatory environment are fostering competition in both the electric and gas businesses. The proliferation of NUGs or Independent Power Producers (IPPs) aided by federal and state statutes which provide them guaranteed markets at rates in excess of the Company's internal cost of production, has put significant upward pressure on the Company's electric rates. During the past several years, the Company's industrial rates have moved from being among the lowest in New York State and the Northeast to approximately the middle of the range. Such increases in rates are reaching a point where industrial customers must balance the benefits and costs of self-generation against retention of utility service. More importantly, industrial and commercial customers may also consider moving operations outside of the Company's service territory. Loss of industrial and commercial customers places additional cost burdens on remaining customers. The potential loss of jobs in the Company's service territory would put further pressure on rates to remaining customers and on the State's social services delivery system.

Similar issues face the gas business, as greater federal emphasis is placed on increasing competition for in[illegible]e supply and delivery. Although competitive pressures [illegible]d principally to pipelines and industrial customers, the possibility of retail competition is growing. Formation of the Gas SBU in 1991 has focused efforts on positioning the business to take advantage of the changing environment, by optimizing its gas supply portfolio to achieve lower costs without sacrificing reliability and by aggressively marketing its gas service to potential or existing customers near its distribution lines.

The Measured Equity Return Incentive Term (MERIT) program, as discussed in more detail below, and the continuing self-assessment process embody the improvements in performance necessary to mitigate bill impacts and their attendant effects. Measures that compare Company cost and service performance with a peer group of similarly situated Northeast utilities will be included in MERIT beginning in 1993. Over the next three years, increasingly challenging performance targets for these external indicators will be established, designed to bring the Company to top-quartile performance within the peer group. Achieving these targets would demonstrate the Company's ability to respond favorably to challenges facing utilities and to mitigate the bill impact consequences discussed above.

The Company must successfully manage, among other things, the economics of the continued operation of Unit 1, implementation of the Clean Air Act Amendments of 1990 and remediation of hazardous waste sites, while responding to the challenges and taking advantage of the opportunities of the Energy Policy Act of 1992 and addressing the opportunities of expanded gas supply competition, as well as continuing implementation of its strategies to reduce bill impacts stemming in large part from the proliferation of excess high-cost NUG power. Through initiatives such as "core process redesign," the Company will also continue its internally directed self-assessment, emphasizing low cost operations and employee empowerment without compromising service to customers.

Regulatory Agreements

The Company's results during the past three years have been strongly influenced by several regulatory agreements it has entered into. A brief discussion of the key terms of certain of these agreements is provided below.

1989 Agreement

The 1989 Agreement represented a bellwether settlement and a significant change in the approach of the Company and the Public Service Commission (PSC) Staff to the ratesetting process. 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 level. This was accomplished 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. Substantially all of the interest coverage deferrals will be recovered by the end of 1993.

In return for stabilizing its financial condition, the Company agreed to formalize the process by which it had been developing a Vision and Mission Statement and a self-assessment process for continual improvement in the way its business is managed. The creation of an incentive return mechanism was recommended to provide the Company opportunity to earn an incremental return on equity based on performance targets designed to reflect improvements in the efficiency and effectiveness of its organization and management.

The Company also agreed to study the advantages and disadvantages of separation, sale or other action with respect to its gas business and submit a study of the advantages and disadvantages of continuing the operation of Unit 1. Based upon the benefits identified in the gas study and consistent with the results of the self-assessment process, the Company reorganized its electric and gas operations into SBUs effective July 1, 1991. The Company performed the Unit 1 economic study and filed a report dated March 28, 1990 which concluded that continued operation of Unit 1 was in the best interest of the ratepayers. Although the PSC Staff disputed certain assumptions used in the study, no further action was taken. In the 1991 Financial Recovery Agreement discussed below, the Company agreed to update its Unit 1 economic study prior to each refueling cycle and make it available to the PSC Staff (See Note 8 of Notes to Consolidated Financial Statements).

1991 Financial Recovery Agreement

The 1991 Financial Recovery Agreement (1991 Agreement) established the $190.0 million temporary rate increase that became effective January 1, 1991 as permanent and provided 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 increased 1.0% ($5.5 million) on July 1, 1992.

The 1991 Agreement included several key elements which represent departures from the Company's prior rate setting methodology. Two of these elements, the Niagara Mohawk electric revenue adjustment mechanism (NERAM) and the MERIT are discussed in more detail below.

The NERAM requires the Company to reconcile actual results to forecast electric public sales gross margin as defined and utilized in establishing rates. The NERAM produces certainty in the amount of electric gross margin the Company will receive in a given period to fund its operations. While reducing risk during periods of economic uncertainty and mitigating the variable effects of weather, the Company does not benefit from unforseen growth in sales. Depending on the level of actual sales, a liability to customers is created if sales exceed the forecast and an asset is recorded for a sales shortfall, thereby generally holding recorded electric gross margin to the level forecast in establishing rates. The 1991 Agreement provides for the operation of the NERAM through June 30, 1993. Recovery or refund of accruals pursuant to the NERAM is accomplished by a surcharge (either plus or minus) to customers over a twelve month period, to begin when cumulative amounts reach certain levels specified in the 1991 Agreement. Reconciliations were initiated on July 1, 1991, June 1, 1992 and December 1, 1992 and the balances to be collected were reclassified to Accounts Receivable. As of December 31, 1992, the Company had a recoverable NERAM balance (amounts subject to reconciliation) of $11.6 million.

The MERIT program is the incentive mechanism created in contemplation of the provisions of the 1989 Agreement which originally allowed the Company to earn up to $180 million of additional return on equity through May 31, 1994. The MERIT program provided for a total of $60 million of the $180 million pool during 1991, $30 million for the measurement period January 1 through May 31, 1991 and $30 million for the balance of calendar 1991.

The PSC granted the full $30 million of MERIT award the Company claimed for the period January 1, 1991 through May 31, 1991. Criteria for earning the initial $30 million of incentive return for the period ending May 31, 1991, encompassed nuclear performance, progress in implementing ideas to capture savings identified in the self-assessment process, customer satisfaction indicators and a reduction in the layers of management. This award, amounting to approximately $.14 per share, was reflected in earnings in the third quarter of 1991 and was collected over the period October 1991 through June 1992.

MERIT goals for the period June 1, 1991 through December 31, 1991 included measures of responsiveness to customers, implementation of self-assessment ideas, nuclear and non-nuclear generation and planning and environmental awareness. The potential value of MERIT for this period was also $30 million. Of this amount, the PSC granted $22.8 million, or approximately $.11 per share. The difference between the Company filing requesting $26 million and the ultimate award was related to implementation of self-assessment cost savings measures. The Company accrued the MERIT award in June 1992 in Accounts Receivable and it is being collected over the period July 1992 through May 1993.

The Company and the PSC Staff reached an agreement, which was approved by the PSC on July 9, 1992, to amend the 1991 Agreement as it related to the MERIT incentives for 1992 and beyond. The amendment realigns the MERIT schedule to make it consistent with the Company's schedule for achieving its Corporate Vision by 1995. The agreement makes available $25 million of MERIT in 1992, $30 million in 1993, $35 million in 1994 and $40 million in 1995. This extends the original period by 18 months and totals $130 million, making available during this period $10 million more than under the original agreement. In addition, agreement has been reached to reopen negotiations in 1993 to determine whether additional MERIT incentives should be established for 1994 and 1995.

Measurement criteria for the $25 million of MERIT for 1992 focus on implementation of self-assessment recommendations, including measures of responsiveness to customers, nuclear performance, cost management and environmental performance. A report supporting the achievement of MERIT for 1992 was submitted to the parties to the 1991 Agreement on February 12, 1993. The Company claimed an award of approximately $14.3 million, which is expected to be billed to customers beginning in May 1993, after PSC confirmation of the earned award. The shortfall from the full award available reflects the increasing difficulty of achieving the targets established in customer service and cost management, as well as lower than anticipated nuclear operating performance.

Criteria for the 1993-1995 MERIT periods are currently being negotiated. Although individual goals have not been decided, progress is being made on the framework within which individual goals will be established. The three focus areas are: (1) Responsiveness to Customer Needs, (2) Efficiency through Cost Management, Improved Operations and Employee Empowerment and (3) Aggressive, Responsible Leadership in Addressing Environmental Issues. The Company expects that targets for full award of MERIT will be more exacting and the Company's success through the first three MERIT periods may not be indicative of future accomplishments.

1993 Rate Settlement

Early in 1992, the Company filed for a $163.7 million rate increase to become effective January 1, 1993, consisting of an electric increase of 4.6% ($137.1 million) and gas increase of 4.7% ($26.6 million). The significant components of the request related to a $55 million increase in operating expenses, increased environmental site investigation and related remediation expenditures of $28 million, current recovery of the $44 million provision for certain post-employment benefits (OPEB) under a new accounting pronouncement and inclusion, as now required by the PSC, of $37 million of NUG capacity payments in base rates versus passing these costs through the fuel adjustment clause.

On September 14, 1992, the Company, the PSC Staff and other intervenors submitted a rate settlement plan (1993 Rate Settlement) to the PSC for approval. The 1993 Rate Settlement increases the Company's revenues by $108.5 million (3.1%) for the year ended December 31, 1993 through changes in rates for electric and gas service. Electric revenues increase $98.4 million or 3.4%, while gas revenues rise by $10.1 million, or 1.8%. The 1993 Rate Settlement was approved by the PSC on January 27, 1993, and new rates were implemented shortly thereafter. Retroactive application of the new rates to January 1, 1993 has been authorized by the PSC.

The increase reflects an allowed return on equity of 11.4%, which is below the 12% requested by the Company in its original filing and the 12.3% reflected in the 1991 Agreement for 1992. A decrease in the Company's cost of capital, including the reduction in return on equity, and allowance for post-retirement benefits in an amount substantially below the amount requested by the Company, accounts for substantially all of the difference from the Company's requested revenue increase. The difference in the post-retirement benefit allowance of approximately $33 million will be deferred pending the outcome of the PSC's consideration of a Statement of Policy addressing post-retirement benefits. The Company anticipates the release of the PSC's final Statement of Policy by no later than the first quarter of 1993. Pending issuance of the Statement of Policy, the 1993 Settlement establishes the intent of the parties for the Company to recover the deferral over a period not to exceed ten years. As discussed in Note 7 of Notes to the Consolidated Financial Statements, the Company expects that both the 1993 Settlement and the policy contemplated in the PSC's proposed Statement of Policy will allow the Company to record a regulatory asset for the difference between the allowance in rates and the full accrual for post-retirement benefits calculated in accordance with the new accounting pronouncement.

Other allowances contributing to the increase in revenues include increased amounts for hazardous waste site investigation and remediation costs, capacity payments to non-utility generators and slightly higher operating costs, as well as inclusion in base rates of costs previously recovered through surcharges. Beginning in 1993, DSM program costs, exclusive of rebates, will be recovered through base rates rather than through a separate surcharge. Based on its cumulative experience in managing DSM programs, the Company believes that base rate treatment is appropriate. The settlement also includes extension of the NERAM through December 1993 and provisions to defer expenses related to the Company's NUG Action Plan, including NUG contract buyout costs and certain other items.

The 1993 Settlement allows the Company to submit a second-stage filing in 1993 to consider revenue requirements that may arise as the result of negotiating a new contract. The Company's current labor agreement expires May 31, 1993.

On February 19, 1993, the Company filed for a gas rate increase of 3.8% or $23.2 million, while submitting a motion to defer an electric base rate filing for 60 days. The Company will use that time to attempt to reach an agreement with the PSC to extend certain cost recovery mechanisms in the 1993 electric rate settlement without increasing base rates. The Company has requested that the results of both the deferral request and the gas filing become effective January 1, 1994. The increase in gas rates is to cover slightly higher operating expenses, as well as higher real estate taxes, property-related costs and construction-related costs. While some parties are actively petitioning the PSC to curtail or suspend the use of settlements in lieu of litigated rate cases, the Company believes that all participants have gained from the settlement process. In an Order issued and effective December 30, 1992, the PSC initiated a statewide proceeding to investigate and develop a ratesetting process encompassing long-term planning goals, rate strategies and resource utilization.

Non-Utility Generators

The most significant factor increasing the Company's costs and its customer bills has been the requirement to purchase non-utility generator power at amounts in excess of its internal cost of production and in volumes greater than needs. The Public Utility Regulatory Policies Act of 1978 (PURPA), New York State Law and PSC policies and procedures collectively require that the Company purchase this power from qualified NUGs. The price used in negotiating purchased power contracts with NUGs (Long Run Avoided Costs, or "LRACs") is established periodically by the PSC. Until repeal in 1992, the statute which governed many of these contracts had established the floor on avoided costs at $0.06/kwh. This, in combination with other factors, has attracted large numbers of potential NUG projects to the Company's service territory.

As of December 31, 1992, 137 of these qualified NUGs with a combined capacity of 1,549 MW were on line and selling power to the Company. For the year ended December 31, 1992, NUG purchases were approximately $543 million, averaging $.0629/kwh. These purchases accounted for approximately 56% of the Company's fuel and purchased power costs but only approximately 22% of the Company's energy supply. During 1991, the Company was required to pay these producers, which accounted for approximately one-third of the Company's fuel and purchased power costs, $268 million, averaging $.0623/kwh. The Company estimated that the cost of power in the marketplace, in the absence of the mandate that it purchase from NUGs, would have been about $0.03/kwh. These increases are being passed on to ratepayers through the operation of the fuel adjustment clause mechanism (FAC).

Some of the uncertainty surrounding the Company's planning for future additional and replacement generating facilities has been removed. Legislative and regulatory action, coupled with aggressive actions by the Company to control costs and restructure contracts, have combined to address the problem of excessive and costly non-utility generated power. New York State has repealed a provision known as the Six Cent Law that provided NUGs a minimum price of $0.06/kwh for qualifying projects. The repeal was part of a comprehensive energy law which also contains measures designed to promote competitive bidding for NUG power and to require any entity, either utility or non-utility, planning a generating facility to demonstrate the need for the facility. In June 1992, the PSC also reduced its LRAC estimates from previous high levels that had attracted an excess of NUG projects. The Six-Cent Law repeal "grandfathered" the minimum price for NUG projects which had signed contracts filed with the PSC by June 26, 1992. Although the Company estimates its total NUG capacity in 1995 to be 2,651 MW, the exact amount is dependent upon the outcome of a number of projects for which construction has not yet begun. Most of the additional capacity above the 1,549 MW in place will qualify for the six-cent subsidy. This would represent approximately 30 percent of the Company's then available capacity but comprise more than 70 percent of its fuel and purchased power costs. As NUG projects come to completion, the Company expects a continued rise in the cost of its purchased power, which will likewise increase the price of retail electricity through the operation of the FAC. Without any other actions, the Company's installed capacity reserve margin will grow to 42%-51% in 1995, as compared to its target of 18%, before beginning to decline in the late 1990's.

These estimates exclude approximately 6,000 MW of energy and capacity that, in the Company's estimate, are not likely to mature into actual projects. Most of this additional amount relates to possible projects that are either in the initial discussion or negotiation stages. Repeal of the Six-Cent Law and reductions in PSC adopted LRACs should significantly lower the costs to be paid for such power and may discourage many of these NUG developers from continuing to pursue those projects.

On August 18, 1992, the Company filed a petition with the PSC which calls for the implementation of "curtailment procedures." This would allow the Company to limit its purchases from NUGs when demand is low and could, if approved, reduce purchased power costs by approximately $30 million annually. The Company has been joined by two other New York State utilities in the proceeding in support of curtailment. The PSC has assigned an Administrative Law Judge to collect and compile a record on the petition and open the issue for public comment. The Judge will then make a recommendation to the PSC based on this evidence. Settlement discussions have commenced and a decision on the petition is expected early in 1993.

On October 23, 1992, the Company also petitioned the PSC to order NUGs to post letters of credit or other firm security to protect ratepayers' interests under certain types of NUG contracts based on now outdated LRACs. Such contracts establish the possibility of a refund to the Company, for the benefit of its ratepayers, for power purchased at prices in excess of the Company's actual avoided costs. Such refunds have the potential to aggregate as much as $7.3 billion over the next 15 years (in excess of $1.7 billion by 1995) and would be credited to ratepayers in the form of rates lower than prevailing rates over the final phase of the contracts. The Company seeks to ensure the availability of these funds to the benefit of its customers by imposition of an ongoing requirement that each affected NUG post firm security in amounts sufficient to protect ratepayers. The

Company cannot predict the outcome of this petition.

Most recently, the Company filed a petition on January 14, 1993, requesting authorization to verify that all cogenerating facilities under contract are maintaining "qualifying facility" status, and are thus entitled to the prices the Company is mandated to pay them. The Company currently has power-purchase agreements with 72 such cogenerators, 47 of which are in commercial operation and producing a total of 1,238 MWs. The proposed monitoring program calls for cogenerators to verify their qualifying facility status annually. Each contract specifies the consequences of failure to maintain such status, which range from contract termination to a reduction in the power purchase price.

Unit 1 Economic Study

Under the terms of the 1989 Agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Unit 1, prior to the start of each refueling outage. The first report, which recommended continued operation of Unit 1 over the remaining term of its license (2009), was filed with the PSC in March 1990.

On November 20, 1992 the Company submitted to the PSC an updated economic analysis which indicated that Unit 1 can be expected to provide value to customers and shareholders at least through its next fuel cycle, which will end in early 1995. The study also indicated that the Unit could continue to provide benefits for the full term of its license if operating costs can be reduced and generating output improved. The Company is aware of only one formal response to its study, from Independent Power Producers of New York (IPPNY), which claims that continued operation of Unit 1 is uneconomic. The Company believes the assertions of IPPNY to be flawed.

The study analyzed a number of scenarios, resulting in break-even capacity factors ranging from 44% to 122%. The "base" case assumes a capacity factor of 61%, which is consistent with the target reflected in the current Unit 1 operating incentive mechanism, and also assumes future operating and capital costs slightly lower than historical performance. While a benefit should be realized from operating the Unit for at least the next two years (one fuel cycle), the study indicates there could be a negative net present value in excess of $100 million if the Unit were to be operated over its remaining 17-year license period. Under an "improved performance case," the Unit is assumed to operate at a 70% capacity factor with future operating and capital costs consistent with industry average performance. The Company believes these goals are achievable for Unit 1. The "improved performance case" results in positive net present value in excess of $100 million for the Unit to operate over its remaining life. Such results are indicative of the volatility of the assumptions and of the uncertainties involved in developing the Unit's economic forecast.

The study necessarily relies on a number of significant assumptions which are subject to uncertainty and could produce a wide range of outcomes. These assumptions include the Unit's capacity factor, levels of operating and capital costs, anticipated demand for electricity, anticipated supply of electricity (including NUG power), implementation and compliance costs of the 1990 Clean Air Act and other federal and state environmental initiatives and fuel availability and prices, especially natural gas. Given the potential for rapid and substantial change in any or all of these assump-tions, the Company will be developing operationa external measures intended to initiate prompt pe reassessments of the economic viability of the Unit.

The Company is also preparing a formal decommissioning preparation and implementation plan to support an orderly and efficient retirement of the plant in the event a decision is made to retire the Unit prior to the expiration of its license.

An agreement with the PSC allows recovery of all reasonable and prudently-incurred sunk costs and costs of retirement, should a prudent decision be made to retire Unit 1 before early 1995. All parties to the 1991 Agreement reserved the right to petition the PSC to institute a formal investigation to review the prudence of any Company decision to retire Unit 1. Any such decision by the Company will be made in consultation with governmental and regulatory authorities.

The Company's net investment in Unit 1 is approximately $600 million. Based upon the Company's 1989 study, the cost of decommissioning Unit 1 is estimated to be approximately $248 million in 1992 dollars. An update of the study is currently underway as part of the formal decommissioning plan discussed above. The Company has collected $75.9 million in rates through 1992, of which $43.1 million has been deposited in an external trust which has accumulated a balance of $46.4 million including earnings on fund investments.

The Company is examining its competitive situati future strategic direction. Among other things, it has ied the economics of continued operation of its fossil plants, given current forecasts of excess capacity. Growth in NUG supply sources and compliance requirements of the Clean Air Act are key considerations in developing the supply segment for the Company's integrated electric resource planning. While the Company's coal-burning plants continue to be cost advantageous, certain older units and certain gas/oil-burning units are being carefully assessed in the planning process to evaluate their economic viability and estimated remaining useful lives.

Federal Budget Proposals

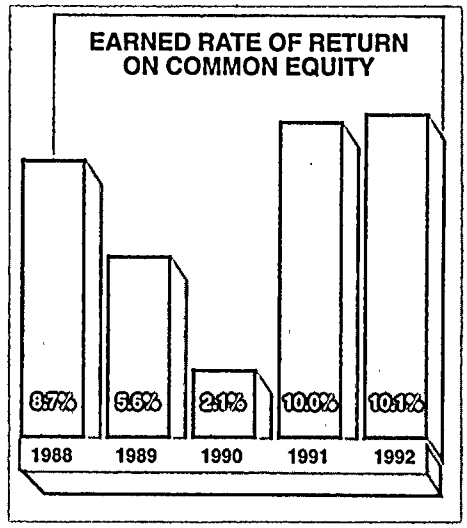
On February 17, 1993 President Clinton proposed to Congress an economic stimulus package that includes an increase in the corporate tax rate from 34% to 36% and a BTU (British Thermal Unit) energy tax. The BTU tax would be phased in over 3 years beginning in mid 1994, and when fully implemented would be at a base rate of 25.7 cents per million BTU with a supplemental tax of 34.2 cents per million BTU for oil. The tax would generally be applied to fossil fuels, nuclear and hydropower in electric generation. The proposals have not been formalized and the specific details of the taxing mechanisms are not yet available. The proposals must still be approved by Congress.

Results of Operations

Earnings for 1992 were $219.9 million or $1.61 per share compared with $203.0 million or $1.49 per share in 1991 and $40.6 million or $.30 per share in 1990. Factors contributing to the increase in earnings in 1992 as compared to 1991 include rate increases for gas and electric customers effective July 1, 1991 and July 1, 1992, and cost management of operating expenses relative to amounts provided in rates, offset by oil and gas writeoffs. The 1991 increase over 1990 is due primarily to the impact of the loss accrued for disallowed Unit 1 and Unit 2 replacement power costs and capacity costs associated with outages, which had reduced earnings by $.68 per share in 1990. 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 in 1990. In addition to the negative earnings impact associated with the liability related to Unit 1 replacement power cost and the Unit 2 replacement power cost liability established in the 1990 Unit 2 Cost Settlement, the Company absorbed approximately $104 million of Unit 1 operating and maintenance costs in excess of amounts provided for in the ratesetting process.

In 1992, the Company's return on common equity improved to 10.1% from 10.0% in 1991 and 2.1% in 1990. Excluding the replacement power cost disallowance, the return on common equity would have been 6.9% for 1990. The Company's allowed return on common equity for utility operations was 12.3% for the year ended December 31, 1992. Factors contributing to the earnings deficiency in 1992 include lower than expected results from the Company's Canadian oil and gas subsidiary, operating expenses higher than amounts provided for in rates and continued exclusion of Unit 2 tax benefits from the Company's rate base (upon which customers would pay a return) offset by reduced interest costs resulting from lower interest rates and an extensive refinancing program in 1992. The earnings deficiency experienced in 1991 resulted from similar causes, as well as from lower gas sales due to warmer than forecasted temperatures.

Non-cash earnings in 1992 were 16.0% of earnings available to common stockholders as compared to 6.6% in 1991. 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 represented in [illegible] of 57% of earnings available to common stockholders before the accrual of the Unit 1 and Unit 2 replacement power cost liability. Deferred costs are being recovered over a period no longer than three years, beginning July 1, 1990. The recovery of the deferral decreased the percentage of non-cash earnings in 1991 and 1992. The Company estimates non-cash earnings will represent approximately 8% of total earnings in 1993.



The Company anticipates a return on equity of between 10% and 11% in 1993. The 1993 allowed return on common equity for utility operations, which excludes any MERIT and demand-side management (DSM) incentive awards, is 11.4%. Factors contributing to the projected 1993 earnings deficiency include continued exclusion of Unit 2 tax benefits from rate base, forecasted returns from the Company's subsidiary operations below the allowed return on utility operations and operating expenses higher than amounts forecast and provided for in rates. The ability to achieve or exceed this level of earnings is dependent upon a number of key factors, including the ongoing control of expenses, earning MERIT and DSM incentives and realization of an anticipated growth in gas sales.

The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1992. It may not be indicative of future operations or earnings. It should also be read in conjunction with the Notes to Consolidated Financial Statements and other financial and statistical information appearing elsewhere in this report.

	Increase (decrease) from prior year *(In millions of dollars)*			
Electric revenues	1992	1991	1990	Total
Increase in base rates	$250.6	$181.3	$ —	$431.9
Fuel and purchased power cost revenues	(6.4)	(83.0)	142.8	53.4
Sales to ultimate consumers	39.7	2.6	49.3	91.6
Sales to other electric systems	(12.8)	36.2	11.8	35.2
DSM revenue	(24.3)	17.2	22.2	15.1
Miscellaneous operating revenues	(11.3)	77.2	(7.4)	58.5
NERAM revenues	7.8	38.8	(5.0)	41.6
MERIT revenues	(2.9)	27.3	—	24.4
Unbilled electric revenues	—	(17.0)	(5.7)	(22.7)
Cash surcharge revenues	—	(42.6)	42.6	—
	$240.4	$238.0	$250.6	$729.0

Electric revenues increased $729.0 million or 30.1% over the three-year period. This increase results primarily from rate increases, net recoveries through the fuel adjustment clause and other factors as indicated in the table on page 23. Nearly three-quarters of the increase in base rates in 1991 and 1992 reflect an increase in the base cost of fuel, which would typically result in a similar decrease in fuel and purchased power cost revenues, thus having a revenue neutral impact. However, purchased power costs have increased significantly during this period, offsetting the otherwise expected decrease. See "Financial Position, Liquidity and Capital Resources" for a discussion of the rate increases and provisions of the regulatory agreements in effect during this period.

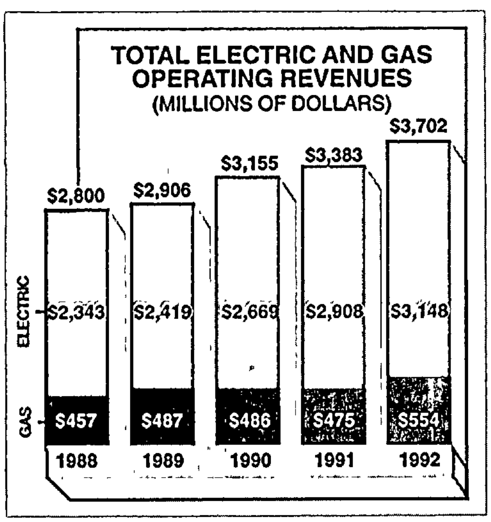
While sales to ultimate customers in 1992 were almost equal with 1991, this level of sales was substantially below the forecast used in establishing rates for the year. As a result, the Company accrued NERAM revenues of $41.7 million ($.20 per share) into electric revenues during 1992 as compared to $33.9 million ($.17 per share) of NERAM revenues in 1991.

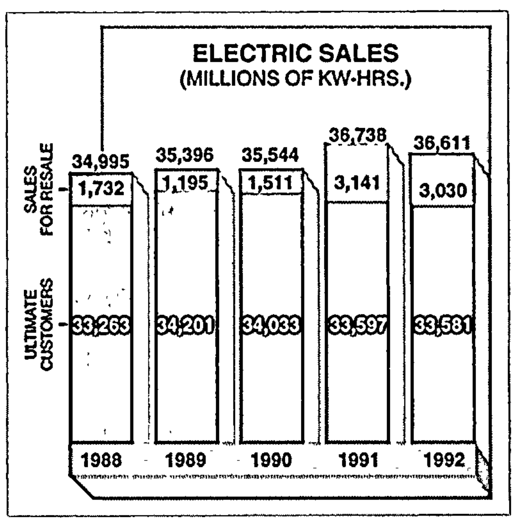
Changes in fuel and purchased power cost revenues are generally margin-neutral, while sales to other utilities, because of regulatory sharing mechanisms, generally result in low margin contribution to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. Approximately $77.8 million of unbilled electric revenues 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 1990 fuel and purchased power cost revenues are replacement power costs associated with the Unit 1 outage. Electric revenues reflect the billing of a separate factor for 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. Cash surcharge revenues were recorded only in 1990 in accordance with the 1989 Agreement, in an effort to achieve minimum specified cash coverage levels.

Electric kilowatt-hour sales were 36.6 billion in 1992, a decrease of .3% from 1991 but an increase of 3.0% over 1990. The 1991 increase reflects increased sales to residential and commercial customers and other electric systems, partly offset by decreased industrial sales due primarily to the economic recession. (See Electric and Gas Statistics – Electric Sales appearing on page 52.) The Company expects an approximate 2% growth in sales to ultimate consumers in 1993. The effects of the recession that began in 1990 are expected to continue to put downward pressure on industrial sales, which may be offset by growth in commercial and residential sales. In any event, the electric margin effect of actual sales in 1993 will be adjusted by the NERAM.

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

Class of service	1992 % of Electric Revenues	% Increase (decrease) from prior years					
		1992		1991		1990	
		Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	34.8%	11.3%	0.7%	7.4%	0.1%	8.8%	(0.5)%
Commercial	36.9	11.1	(0.5)	6.7	0.5	12.0	1.7
Industrial	20.0	12.9	(0.2)	2.5	(4.3)	11.8	(2.5)
Municipal service	1.6	5.8	(0.4)	6.1	0.9	6.0	(0.9)
Total to ultimate consumers	93.3	11.4	0.0	6.1	(1.3)	10.6	(0.5)
Other electric systems	3.0	(12.1)	(3.5)	51.9	107.9	20.3	26.4
Miscellaneous	3.7	(29.0)	—	44.2	—	0.1	—
Total	100.0%	8.3%	(0.3)%	8.9%	3.4%	10.4%	0.4%





As indicated in the table below, internal fossil fuel production declined in 1992, principally at the Oswego oil-fired facility and Albany gas-fired station, corresponding to an increase in required NUG purchases combined with scheduled outages. Nuclear production declined in 1992 as a result of a Unit 2 refueling outage and several unscheduled outages at Unit 1. In [illegible] both Units are scheduled to be refueled. Unit 1 operated at a capacity of 54.2% for 1992, while Unit 2 operated at 54.5%.

	1992		1991		1990		% Change from prior year			
							1992 to 1991		1991 to 1990	
Fuel for electric generation: *(in millions of dollars)*	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost
Coal	8,340	$128.8	8,715	$139.6	8,678	$139.6	(4.3)%	(7.7)%	0.4%	0.0%
Oil	3,372	106.6	5,917	187.6	7,109	232.3	(43.0)	(43.2)	(16.8)	(19.3)
Natural Gas	1,769	44.6	1,980	54.6	1,950	56.1	(10.7)	(18.4)	1.5	(2.7)
Nuclear	5,031	28.9	6,561	45.2	2,975	30.7	(23.3)	(36.2)	120.5	47.3
Hydro	3,818	—	3,468	—	4,024	—	10.1	—	(13.8)	—
	22,330	308.9	26,641	427.0	24,736	458.7	(16.2)	(27.7)	7.7	(6.9)
Electricity purchased:										
NUGs	8,632	543.0	4,303	268.1	3,041	197.8	100.6	102.5	41.5	35.5
Other	8,917	115.7	9,067	125.6	10,660	181.8	(1.7)	(7.9)	(14.9)	(30.9)
	17,549	658.7	13,370	393.7	13,701	379.6	31.3	67.3	(2.4)	3.7
Fuel adjustment clause	—	6.0	—	17.2	—	39.6	—	(65.1)	—	(56.6)
Losses/Company use	3,268	—	3,273	—	2,893	—	(0.2)	—	13.1	—
	36,611	$973.6	36,738	$837.9	35,544	$877.9	(0.3)%	16.2%	3.4%	(4.6)%

1991 kilowatt-hour generation increased 7.7% and fuel costs incurred decreased 6.9% as a result of increased generation [illegible] the Company's nuclear units. 1991 kilowatt-hour purchases decreased 2.4% as a result of the return to service of Unit 1, [illegible] costs incurred increased 3.7% as a result of a 6.3% increase in the average cost per kilowatt hour.

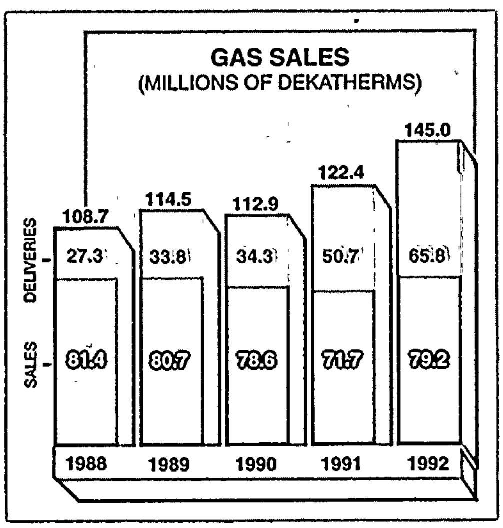
Gas revenues increased $66.5 million or 13.6% over the three-year period. As shown by the table below, this is primarily attributable to increased base rates effective in 1992 and 1991, increased revenues from transportation of gas for others and increased sales to ultimate consumers. Although rates 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 has been considered in the ratesetting process and has not had a significant impact on earnings. Also, changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year *(In millions of dollars)*			
Gas revenues	1992	1991	1990	Total
Increase in base rates	$ 4.7	$ 22.6	$ —	$27.3
Transportation of customer-owned gas	6.3	14.4	2.2	22.9
Purchased gas adjustment clause revenues	12.4	(25.7)	5.3	(8.0)
MERIT revenues	(0.3)	2.7	—	2.4
Miscellaneous operating revenues	2.6	3.5	(2.0)	4.1
Sales to ultimate consumers and other sales	52.9	(27.7)	(7.4)	17.8
	$78.6	$(10.2)	$(1.9)	$66.5

Gas sales, excluding transportation of customer-owned gas, were 79.2 million dekatherms in 1992, a 10.4% increase from 1991 and a .7% increase from 1990 (See Electric and Gas Statistics – Gas Sales appearing on page 52.) The increase in 1992 includes a 12% increase in residential sales and a 10.2% increase in commercial sales, which were strongly influenced by weather, offset by a 2.2% decrease in industrial sales reflective of fuel-switching and the recession. The decrease for 1991 includes a 3.6% decrease in sales in the residential class reflecting milder weather factors, an 11.4% decrease in sales in the commercial class and a 56.0% decrease in sales in the industrial class reflecting the recession and fuel-switching. The changes in the sales mix for 1990 through 1992 reflect more severe weather, unfavorable competition with oil prices and the ability of large customers to purchase gas directly from producers. In 1992, the Company transported 65.8 million dekatherms (a 30% increase from 1991) for customers purchasing gas directly from producers and expects a continued increase in such transportation activities. The Company has forecast an increase in total gas deliveries in 1993 in excess of 5.3% of 1992 weather-adjusted deliveries principally in the transportation category, although public sales are expected to increase almost 1.5%. Factors impacting these increases include the effects of the recession that began in 1990, the relative price differences between oil and gas in combination with the relative availability of each fuel, the expanded number of cogeneration projects served by the Company and increased marketing efforts. In 1992, the Ga added 11,000 new customers, primarily in the resi class, an increase of 2.3%, and expects a similar in in new customers in 1993. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

Class of service	1992 % of Gas Revenues	Increase (decrease) from prior years 1992 Revenues	1992 Sales	1991 Revenues	1991 Sales	1990 Revenues	1990 Sales
Residential	64.0%	17.0%	12.0%	(1.4)%	(3.6)%	(3.2)%	(5.6)%
Commercial	23.9	16.6	10.2	(11.5)	(11.4)	2.0	(1.4)
Industrial	1.8	18.6	(2.2)	(56.4)	(56.0)	57.0	57.6
Total to ultimate consumers	89.7	16.9	11.1	(6.6)	(8.7)	(0.2)	(2.2)
Other gas systems	.9	(32.0)	(21.7)	(11.9)	(11.8)	(14.7)	(14.7)
Transportation of customer-owned gas	7.7	17.2	30.0	65.0	47.9	11.4	1.4
Miscellaneous	1.7	38.5	—	574.1	—	(84.0)	—
Total	100.0%	16.5%	18.5%	(2.1)%	8.4%	(0.4)%	(1.4)%

The PSC approved the 1991 Agreement on June 12, 1991, providing for, among other things, the establishment of permanent gas rates at the same level as the temporary rates effective January 1, 1991 (an increase of $27.2 million or 4.9%) and a $5.5 million or 1.0% increase effective July 1, 1992.



In comparison to the prior year, the total cost of gas purchased increased 16.1% in 1992, after having decreased 13.4% in 1991 and 1.0% in 1990. The increase for 1992 results from increased dekatherms purchased (11.5%), a 1.5% increase in rates charged by suppliers and a $6.9 million increase in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. The decrease for 1991 is the result of a 3.3% ($21.3 million) decrease in dekatherms purchased to meet customer demand at slightly lower rates charged by the Company's suppliers, combined with a decrease of $17.0 million in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. The decrease for 1990 was the result of a 9.2% decrease in dekatherms purchased to meet customer demand, offset by 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 un contract with its principal supplier, to take advant lower spot market prices. Effective July 1, 1991, the Company renegotiated its contract with its principal supplier to provide for even greater flexibility to purchase gas in the spot market and to provide for the utilization of gas storage facilities. Access to these storage facilities was expanded and liberalized in 1992. The Company's net cost per dekatherm purchased increased to $3.45 in 1992 from $3.31 in 1991 and $3.70 in 1990.

Further changes in the federal regulation of gas pipelines, resulting from FERC Order 636 and its amendments issued in 1992, will require interstate pipelines that offer open access transportation services to unbundle pipeline sales services from pipeline transportation service. These changes will enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as arranging for transportation and increased gas storage services. While gas supply flexibility is expected to improve the competitive position of the Company in industrial markets, it must meet the challenge in all markets of increased competition while balancing supply flexibility with system reliability.

As a result of these structural changes, pipelines face "transition" costs from implementation of the order. The principal costs are: unrecovered gas cost that would otherwise have been billable to pipeline customers under previously existing rules, costs related to restructuring gas supply contracts and costs of assets needed to imp the order (such as meters, valves, etc.). Under the Order, pipelines are allowed to recover 100% of prudently incurred costs from customers. Prudence will be determined by the FERC review.

The amount of restructuring costs that may be billable to the Company will be determined in accordance with the restructuring plans which have been submitted to FERC for approval. The Company is actively participating in FERC hearings on these matters to ensure an equitable allocation of costs. Based upon information presently available to the Company from the petitions filed by the pipelines and the Company's participation in settlement negotiations, its liability for the pipelines' unrecovered gas costs could be as much as $56 million and its liability for pipeline restructuring costs could be as much as $60 million. However, the Company believes ultimate liability will be less than $64 million in total, based on its assessment of the progress of settlement negotiations. The Company anticipates these costs will be primarily reflected in demand charges paid to reserve space on the various interstate pipelines and will be billed over a period of approximately 7 years, with billings more heavily weighted to the first 3 years. The Company is unable to predict the probable outcome of current pipeline restructuring settlements and the amounts for which it may be ultimately liable or the period over which this liability will be billed. The Company believes any amounts for which it is ultimately determined to be liable will be recoverable in the ratesetting process.

Through the energy and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric fuel adjustment clause provides for partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a specific portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. In 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.

Other operation expense increased $52.5 million or 7.8% in 1992 as compared to increases of 7.8% in 1991 and 9.5% in 1990. The 1992 increase is primarily due to wage increases (including the effects of the performance based management compensation program and union wage increases), increased computer software expenses and higher medical benefits paid. The 1991 increase is primarily due to wage increases, including the effects of a new performance-based management compensation program and an increase in bad debt expense. The increase is also due to DSM program expenses, environmental site investigation and remediation costs, and research and development costs which totaled approximately $41.9 million, but which are matched with specific revenue factors provided for in the 1991 Agreement. Bad debts have increased as a reflection of the effects of the continuing national recession. Increased collections efforts and innovative collections management begun in 1991 to make long-term improvements also contributed to the short-term effect of increased writeoffs.

Agreement interest coverage (deferral)/amortization reflects the impact on operating expenses from the target interest coverage ratio deferrals allowed under the 1989 Agreement. The 1991 and 1992 amount represents amortization, based on amounts recovered in rates, of deferrals permitted in 1989 and 1990. The 1990 deferral was reduced by $42.6 million of cash surcharge revenues permitted by the 1989 Agreement and $14.8 million of amortization pursuant to the 1991 Agreement. At December 31, 1992, $16.5 million remained to be amortized.

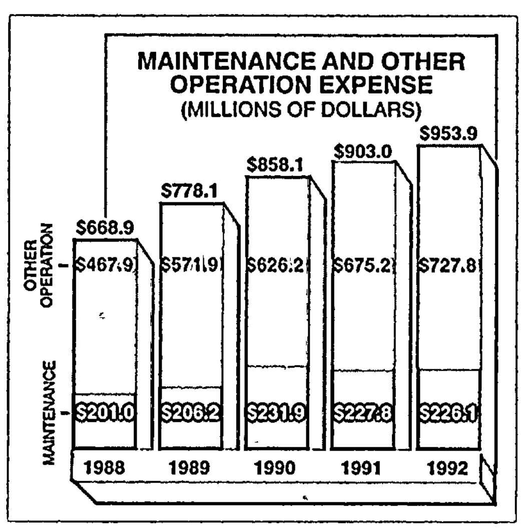
Maintenance expense decreased slightly in 1992 as increased costs associated with outages at Unit 1 and refueling Unit 2 were offset by reduced transmission line maintenance expenses. Maintenance expense decreased 1.8% in 1991 due to lower Unit 2 maintenance partly offset by transmission line ice storm damage, but increased 12.5% in 1990, primarily due to increased levels of maintenance at production steam plants, Unit 2 and on the Company's electric distribution system.

Depreciation and amortization expense for 1992 and 1991 increased 5.9% and 17.2% over 1991 and 1990, respectively. The increase is attributable to normal plant growth; however, the 1991 amount also reflects an $18.2 million increase in the provision for nuclear plant decommissioning.

Net Federal and foreign income taxes for 1992 and 1991 increased as a result of increases in book taxable income. The 1990 taxes decreased as a result of decreases in book taxable income. The increase in **Other taxes** in the three-year period is due principally to higher property taxes resulting from property additions along with increased revenue-based taxes.

Other items, net, excluding Federal income taxes, AFC and the nuclear disallowances decreased $2.7 in 1992 and $21.9 million in 1991. The 1992 decrease is the result of the recording of a $45 million reserve against the carrying value of Canadian subsidiary oil and gas reserves, offset in part by the recognition of the Company's share of Unit 2 contractor litigation proceeds and increased earnings by the Company's independent power subsidiary. The 1991 decrease is primarily the result of a similar writedown of $22.7 million of oil and gas reserves.

Net interest charges decreased $12.0 million in 1992 and $7.2 million in 1991, primarily as the result of the refinancing of debt at interest rates lower than the debt retired. In 1990, net interest charges increased due to the issuance of additional First Mortgage Bonds. Dividends on preferred stock decreased $3.9, $1.9 and $2.9 million in 1992, 1991 and 1990, respectively, 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 8.29% and 7.04%, respectively, in 1992, from 8.74% and 7.53%, respectively, in 1991, from 9.11% and 7.56%, respectively, in 1990.

Effects of Changing Prices
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 methodology 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 Company's 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, 1992 was 56.4% long-term debt, 7.4% preferred stock and 36.2% common equity, as compared to 56.7%, 8.3% and 35.0%, respectively, at December 31, 1991. Book value of the common stock was $16.33 per share at December 31, 1992 as compared to $15.54 per share at December 31, 1991. The improvement in the capital structure and book value is primarily attributable to reinvested earnings, although preferred stock redemptions and sales of common stock under stock purchase plans also had an impact.

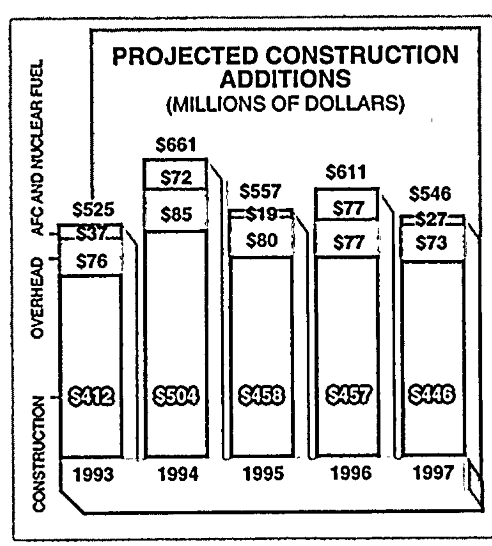
The 1992 ratio of earnings to fixed charges was 2.24 as compared to 2.09 in 1991. The ratio of earnings to fixed charges for 1990 was 1.41, which reflects the effects of the loss accrued for disallowed Unit 1 and Unit 2 replacement power costs as discussed above in Results of Operations. Excluding the effect of the loss accrual, the 1990 ratio would have been 1.82. The 1990 ratio of earnings to fixed charges also reflects the effects of the 1989 Agreement, which provided for near-term financial stabilization while establishing a framework for resolving regulatory and financial issues facing the Company. A key aspect of this financial stabilization was the provision assuring specified interest coverage levels (without AFC) in 1990.

The Company has been made aware that firms which publish securities ratings have begun to impute certain items into the Company's interest coverage calculations and capital structure, the most significant of which is the inclusion of a "leverage" factor for NUG contracts. These firms believe that the financial structure of the NUGs (which typically have very high debt-to-equity ratios) and the character of the power purchase agreements increase the financial risk of utilities. The Company is aware that its reported interest coverage and debt-to-equity ratios have recently been discounted by varying amounts for purposes of establishing credit ratings. Because of the Company's growing commitments for NUG purchases, the imputation can have a material negative impact on its indicators. Standard and Poors recently changed the "outlook" for the Company's secured debt from "positive" to "stable" principally due to NUG commitments.

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. Annual expenditures for the years 1990-1992 for construction and nuclear fuel, including related AFC and overheads capitalized, were $431.6 million, $522.5 million and $502.2 million, respectively.

The 1993 estimate for construction additions, including overheads capitalized, nuclear fuel and AFC, is approximately $525 million, of which approximately 90% 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 $579 million (expected to be refinanced from external sources) to the Company's capital requirements, for a total of $1,104 million. Current estimates of total capital requirements for the years 1994-1997 are $1,170, $784, $813 and $712 million, respectively, of which $661, $557, $611, and $546 million relates to expected construction additions. The estimate of construction additions included in capital requirements for the period 1994 to 1997 will be reviewed by management during 1993 with the objective of reducing these amounts where possible.

The provisions of the Clean Air Act Amendments of 1990 (Clean Air Act) are expected to have an impact on the Company's fossil generation plants during the period through



2000 and beyond. The Company is studying options for compliance with the various provisions of Phase I of the Clean Air Act, which becomes effective January 1, 1995 and continues through 1999, including a possible strategy that focuses on fuel-switching at its facilities. The potential for changing the coal burned at the Dunkirk Steam Station to a lower sulfur content is under review, and converting Oswego Units 5 and 6 from oil to co-firing with natural gas and oil (including construction of a natural gas pipeline to the facility) is included in the construction budget. To meet compliance requirements, the Company must also lower its nitrous oxide (NOx) emissions and has included $85 million in its construction forecast for 1993 through 1997 to install low NOx burners at the Huntley, Dunkirk and Albany Steam Stations. Phase II of the Clean Air Act, effective January 1, 2000, will require further reductions in sulfur dioxide emissions. The Company has conducted studies indicating that the burning of lower sulfur fuels at all its coal and oil fired units is a possible compliance method, but decisions on Phase II have not yet been made. The Company is continuing to study its options, taking into consideration the impacts of emerging environmental laws and regulations at both the Federal and State level and the effect of NUG purchases and DSM initiatives on load forecasts, as well as continuing to examine the emerging market for trading emission allowances.

The Company believes that compliance with the new emission restrictions can be achieved 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. The Company believes that all capital costs, as well as incremental operating and maintenance costs and fuel costs, will be recoverable from its ratepayers.

The Company is also studying draft New York State emissions requirements which, as currently proposed, would be far more restrictive than federal requirements and could cause a substantial increase in compliance cost and, in the most extreme case, require retirement of certain of the Company's fossil fuel plants. The Company is unable to predict what requirements will ultimately be adopted by New York State.

The Company has undertaken a long-term program to reinforce sections of its electric transmission network which are approaching the end of their useful lives. The anticipated cost of the reinforcement effort is approximately $435 million within the period 1993-1997, but the efforts are expected to continue beyond 1997.

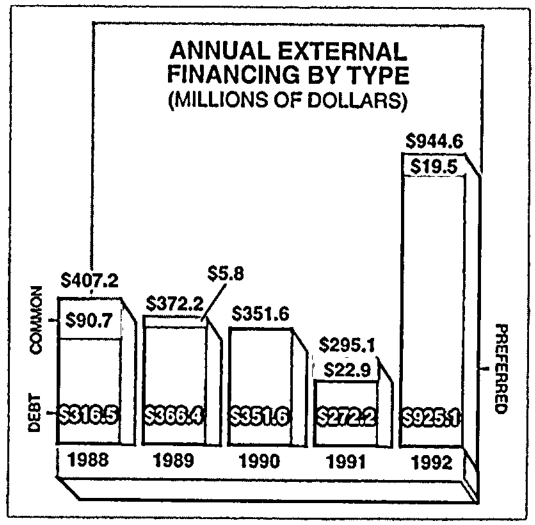
The Company has also included amounts in the construction forecast for hydro relicensing, as well as for gas system expansion for cogeneration and greater customer market penetration.

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 34.

During 1992, the Company raised approximately $944.6 million from external sources, consisting of $835 million of First Mortgage Bonds, $19.5 million of common stock (which includes $6.1 million issued in connection with the acquisition of Syracuse Suburban Gas Company, Inc.) and a net increase of $90.1 million of short-term debt and intermediate term bank revolving credit obligations, which include the refinancings discussed below. The Company also completed $12.5 million of capital lease financing. These amounts include external debt financing done directly by the Company's subsidiaries, which decreased to $20.4 million from $54.2 million in 1991.

During 1992, the Company issued $835 million of First Mortgage Bonds and the proceeds were used to refinance $100 million of maturing bonds and provide for the call and early redemption of $638 million of high coupon First Mortgage Bonds. The Company also refinanced debt underlying a long-term leveraged transmission line lease to reduce the interest rate from 11.1% to 8.77% and entered into a forward refunding agreement to reduce the interest rate on $115.7 million of tax-exempt bonds from approximately 11.3% to 7.2% beginning in 1994.



The Company continues to investigate options to reduce its embedded cost of long-term debt and take advantage of its current bond ratings and lower interest costs.

External financing of approximately $631 million is expected for 1993, of which $438 million is to be used for scheduled and optional refundings. This external financing is projected to consist of $510 million in long-term debt, $100 million from a public offering of common stock and about $41 million through the Company's Dividend Reinvestment and Employee Stock Plans, offset by a $20 million decrease in short-term debt. These common stock sales are consistent with management's goal to improve the Company's capital structure. External financing plans for 1994 to 1997 are subject to periodic revision as underlying assumptions are changed to reflect new developments; however, the Company currently anticipates external financing over this period in the aggregate of approximately $1,177 million. Substantially all of this financing is for refunding, as cash provided by operations is generally expected to provide sufficient funds for the Company's anticipated construction program. The aggregate level of financing during this four year period will reflect, among other things, the nature, timeliness and adequacy of rate relief, uncertain energy demand due to economic conditions, and capital expenditures relating to distribution and transmission load reliability projects, as well as expansion of the gas business. Costs associated with compliance with federal and state environmental quality standards including the Clean Air Act, 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.

The Company has initiated a site investigation and remediation program which seeks a) to identify and remedy environmental contamination hazards in a proactive and cost-effective manner designed to satisfy regulatory requirements and b) to ensure financial participation by other responsible parties. The program involves sponsorship of investigation, remediation and selected research projects for 42 Company-owned waste sites and, where appropriate, participation in remedial action at 42 waste sites owned by others as to which the Company is one of a number of potentially responsible parties (PRP).

The Company has accrued $215 million at December 31, 1992 for its estimated liability for investigation and remediation of certain Company-owned and Company-associated hazardous waste sites. The amount accrued represents the low end of a range of cost estimates developed from the Company's ongoing site investigation and remediation program. Of the $215 million accrued, $195 million relates to Company-owned sites and $20 million represents the Company's estimated cost contribution to sites with which it may be associated. The accrual of the Company's cost contribution for PRP sites is derived by estimating the total cost of clean-up of the sites and then applying a contribution factor to the estimated total cost. Total costs to investigate and remediate sites with which the Company is associated as a PRP are estimated to be approximately $492 million.

The Company believes that costs incurred in the investigation and remediation process are recoverable in the ratesetting process. (See Note 9 of Notes to Consolidated Financial Statements under "Environmental Issues.") The 1991 Agreement included a recovery mechanism and an annual allowance of approximately $9 million for costs expected to be incurred during 1991 and 1992 for site investigation and remediation. The 1993 Settlement provides for annual recovery of $35 million of expected expenditures. The recovery mechanism provides that expenditures over or under the allowance be deferred for future rate consideration. The impact of these expenditures on external financing requirements is dependent upon the timing of expenditures and associated recovery; however, the Company does not expect these costs to impact external financing materially.

The Company is also undertaking an environmental compliance audit program at many of its facilities. These audits may result in additional expenditures for investigation and remediation that the Company cannot currently estimate. Some of the contamination problems the Company might find include petroleum-related contamination caused by past spills, leaks, or other releases incidental to operation at Company facilities.

The Nuclear Regulatory Commission (NRC) issued regulations in 1988 requiring owners of nuclear power p[illegible]s to place costs associated with decommissioning ac[illegible] for contaminated portions of nuclear facilities into [illegible] ternal 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 $364 million and $381 million in future dollars. The 1991 Agreement includes an allowance for nuclear decommissioning of Units 1 and 2 that exceeds the Company's currently determined minimum requirement. These amounts are being placed in an external trust. Pursuant to the terms of the 1991 Agreement, such allowances will be accepted in future years unless and until the cost of decommissioning changes. The Company filed a decommissioning report for each Unit with the NRC in July 1990.

Statement of Financial Accounting Standards No. 106, "Employees' Accounting for Postretirement Benefits Other than Pensions" becomes effective in 1993 (See Note 7 of Notes to Consolidated Financial Statements). The pronouncement requires accrual accounting for these benefits, which the Company currently accounts for on a cash basis. The 1993 Settlement provides for partial recovery of the post-retirement benefit accrual, with authorization to defer the difference for future recovery (see "Rate Agreements" above). The Company is evaluating its funding optio[illegible] the extent the Company funds amounts in an extern[illegible] in excess of the rate allowance, financing require[illegible]s may increase.

The Company believes that traditionally available sources of financing should be sufficient to satisfy the Company's external financing needs during the period 1993 through 1997. As of December 31, 1992, the Company was able to issue an additional $1,689 million aggregate principal amount of First Mortgage Bonds. This includes $954 million on the basis of retired bonds without regard to an interest coverage test and approximately $735 million supported by additional property currently certified and available, assuming an 8% interest rate, under the applicable tests set forth in the Company's mortgage trust indenture. A total of $200 million of Preference Stock is currently available for sale. The Company also has authorized unissued Preferred Stock totaling $342.4 million. The Company will also continue to explore and utilize, as appropriate, other methods of raising funds.

The Company's securities ratings at December 31, 1992, were:

	Secured Debt	Preferred Stock	Commercial Paper
Standard & Poors Corporation	BBB	BBB-	A-2
Moody's Investor Service	Baa2	baa3	P-[illegible]
Duff & Phelps	BBB	BBB-	Not ap[illegible]
Fitch Investors Service	BBB	BBB-	Not ap[illegible]

The security ratings set forth above are subject to revision and/or withdrawal at any time by the respective rating organizations and should not be considered a recommendation to buy, sell or hold securities of the Company.

The Company's cost of financing and access to markets can be negatively impacted by events outside of its control. The Company's securities ratings could be negatively impacted by, among other things, the growth in its reliance on NUG purchase power requirements. Rating agencies have expressed concern about the impact on Company financial indicators and risk that NUG financial leveraging may have.

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. Working capital deficits may also be temporarily created as a result of the seasonal nature of the Company's operations as well as timing differences between the collection of customer receivables and the payment of fuel and purchased power costs. However, the Company has sufficient borrowing capacity to fund such a deficit as necessary. Bank credit arrangements which, at December 31, 1992, totaled $516 million (including $220 million in commitments under Revolving Credit Agreements, $100 million Direct Pay Letter of Credit Facility and Revolving Credit Agreement of Oswego Facilities Trust, $40 million in one-year commitments under Credit Agreements, $56 million in lines of credit and a $100 million Bankers Acceptance Facility Agreement) are used by the Company to enhance flexibility as to the type and timing of its long-term security sales.

The unsecured debt limitation imposed by the Company's charter is 10% of consolidated capitalization plus $50 million, which, as of January 1, 1993, equates to approximately $661 million and against which the Company had outstanding unsecured debt of approximately $315 million.

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 Corporate Policy Register and a Code of Business Conduct which supply employees with a framework describing and defining the Company's overall approach to business and requires all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by Price Waterhouse, the Company's independent accountants, in accordance with generally accepted auditing standards. In planning and performing their audit, Price Waterhouse considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit 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 outside 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 being present.

Report of Independent Accountants

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, 1992 and 1991, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles. 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.

Price Waterhouse

Syracuse, New York
January 28, 1993

Consolidated Balance Sheets

	In thousands of dollars	
At December 31,	1992	1991
ASSETS		
Utility plant (*Note 1*):		
Electric plant	$7,590,062	$7,303,184
Nuclear fuel	445,890	408,643
Gas plant	787,448	718,935
Common plant	231,425	180,456
Construction work in progress	587,437	568,994
Total utility plant	9,642,262	9,180,212
Less: Accumulated depreciation and amortization	2,975,977	2,741,004
Net utility plant	6,666,285	6,439,208
Other property and investments	274,169	313,371
Current assets:		
Cash, including temporary cash investments of $4,121 and $4,321, respectively	43,894	27,378
Accounts receivable (less allowance for doubtful accounts of $3,600) (*Note 9*)	221,165	176,196
Unbilled electric revenues (*Note 1*)	180,000	158,700
Electric margin recoverable	11,595	15,265
Materials and supplies, at average cost:		
Coal and oil for production of electricity	78,517	65,355
Gas storage	20,466	16,373
Other	172,637	154,240
Prepayments:		
Taxes	14,414	17,808
Pension expense (*Note 7*)	33,631	32,877
Other	32,522	36,824
	808,841	701,016
Deferred debits:		
Unamortized debt expense	140,803	108,629
Deferred recoverable energy costs	61,944	47,615
Deferred finance charges (*Note 1*)	239,880	239,880
Deferred operating expenses	16,486	36,743
Deferred environmental restoration costs (*Note 9*)	215,000	200,000
Other	167,127	155,014
	841,240	787,881
	$8,590,535	$8,241,476
CAPITALIZATION AND LIABILITIES		
Capitalization (*Note 4*):		
Common stockholders' equity:		
Common stock, issued 137,159,607 and 136,099,654 shares, respectively	$ 137,160	$ 136,100
Capital stock premium and expense	1,658,015	1,650,312
Retained earnings	445,266	329,130
	2,240,441	2,115,542
Non-redeemable preferred stock	290,000	290,000
Mandatorily redeemable preferred stock	170,400	212,600
Long-term debt	3,491,059	3,325,028
Total capitalization	6,191,900	5,943,170
Current liabilities:		
Short-term debt (*Note 2*)	227,698	131,218
Long-term debt due within one year (*Note 4*)	57,722	175,501
Sinking fund requirements on redeemable preferred stock (*Note 4*)	27,200	26,950
Accounts payable	275,744	247,401
Payable on outstanding bank checks	41,738	36,434
Customers' deposits	13,059	11,070
Accrued taxes	52,033	34,587
Accrued interest	70,882	78,195
Accrued vacation pay	38,515	36,263
Other	40,220	34,956
	844,811	812,575
Deferred credits:		
Accumulated deferred income taxes (*Note 1*)	755,421	699,492
Deferred finance charges (*Note 1*)	239,880	239,880
Unbilled electric revenues (*Note 1*)	77,768	56,468
Deferred pension settlement gain (*Note 7*)	68,292	73,084
Accrued refunds to customers for replacement power cost disallowance	46,801	86,348
Other	150,662	130,459
	1,338,824	1,285,731
Commitments and contingencies (*Note 9*):		
Liability for environmental restoration	215,000	200,000
	$8,590,535	$8,241,476

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	1992	1991	1990
	In thousands of dollars		
Operating revenues:			
Electric	$3,147,676	$2,907,293	$2,669,308
Gas	553,851	475,225	485,411
	3,701,527	3,382,518	3,154,719
Operating expenses:			
Operation:			
Fuel for electric generation	323,200	438,957	460,485
Electricity purchased	650,379	398,882	417,429
Gas purchased	287,316	247,502	285,868
Other operation expenses	727,766	675,224	626,235
1989 Agreement interest coverage (deferred)/amortization	20,257	31,176	(52,970)
Maintenance	226,127	227,812	231,895
Depreciation and Amortization (*Note 1*)	274,090	258,816	220,857
Federal and foreign income taxes (*Note 6*)	183,233	158,137	121,114
Other taxes	484,833	420,578	391,745
	3,177,201	2,857,084	2,702,658
Operating income	524,326	525,434	452,061
Other income and deductions:			
Allowance for other funds used during construction (*Note 1*)	9,648	8,251	10,674
Federal and foreign income taxes	27,729	24,242	12,395
Nuclear replacement power cost disallowance	—	—	(139,974)
Related income tax of cost disallowance	—	—	47,600
Other items (net)	(16,338)	(13,599)	8,251
	21,039	18,894	(61,054)
Income before interest charges	545,365	544,328	391,007
Interest charges:			
Interest on long-term debt	290,734	302,062	311,728
Other interest	9,982	9,577	7,141
Allowance for borrowed funds used during construction	(11,783)	(10,680)	(10,740)
	288,933	300,959	308,129
Net income	256,432	243,369	82,878
Dividends on preferred stock	36,512	40,411	42,300
Balance available for common stock	219,920	202,958	40,578
Dividends on common stock	103,784	43,552	—
	116,136	159,406	40,578
Retained earnings at beginning of year	329,130	169,724	129,146
Retained earnings at end of year	$ 445,266	$ 329,130	$ 169,724
Average number of shares of common stock outstanding (*in thousands*)	136,570	136,100	136,100
Balance available per average share of common stock	$ 1.61	$ 1.49	$ .30
Dividends paid per share	$ .76	$ .32	$ .00

( ) Denotes deduction

Consolidated Statements of Cash Flows

Increase (Decrease) in Cash

	In thousands of dollars		
For the year ended December 31,	1992	1991	1990
Cash flows from operating activities:			
Net income	$256,432	$243,369	$82,878
Adjustments to reconcile net income to net cash provided by operating activities:			
Nuclear replacement power cost disallowance and related amortization	(39,547)	(28,820)	115,168
Depreciation and amortization	274,090	258,816	220,857
Amortization of nuclear fuel	26,159	38,687	27,878
Provision for deferred income taxes	55,929	68,138	(24,881)
Electric margin recoverable	3,670	(20,173)	4,908
Allowance for other funds used during construction	(9,648)	(8,251)	(10,674)
Deferred recoverable energy costs	(14,329)	4,931	41,300
Loss on investments — net	44,296	30,680	8,386
Unbilled electric revenues	—	—	(17,031)
Deferred operating expenses	20,257	31,176	(53,939)
(Increase) decrease in net accounts receivable	(44,969)	(25,900)	54,964
(Increase) decrease in materials and supplies	(28,293)	7,022	(39,031)
Increase (decrease) in accounts payable and accrued expenses	31,025	4,221	(36,122)
Increase in accrued interest and taxes	10,133	447	20,423
Changes in other assets and liabilities	39,565	17,052	106,227
Net cash provided by operating activities	624,770	621,395	501,311
Cash flows from investing activities:			
Construction additions	(452,497)	(504,485)	(418,328)
Nuclear fuel	(37,247)	(13,236)	[illegible]
Less: Allowance for other funds used during construction	9,648	8,251	[illegible]
Acquisition of utility plant	(480,096)	(509,470)	[illegible]
(Increase) decrease in materials and supplies related to construction	(7,359)	4,682	(26,020)
Increase (decrease) in accounts payable and accrued expenses related to construction	7,756	1,055	(9,030)
Increase in other investments	(11,615)	(69,648)	(52,255)
Other	(31,588)	(13,721)	(16,777)
Net cash used in investing activities	(522,902)	(587,102)	(514,936)
Cash flows from financing activities:			
Proceeds from sale of common stock	13,340	—	—
Sale of mortgage bonds	835,000	195,600	300,000
Issuance of preferred stock	—	22,850	—
Redemption of preferred stock	(41,950)	(42,830)	(25,980)
Reductions of long-term debt	(796,795)	(231,941)	(240,110)
Net change in short-term debt and revolving credit agreements	90,130	76,606	51,591
Dividends paid	(140,296)	(83,963)	(42,300)
Change in dividends payable	(893)	257	(9,148)
Other	(43,888)	(7,065)	(4,769)
Net cash provided by (used in) financing activities	(85,352)	(70,486)	29,284
Net increase (decrease) in cash	16,516	(36,193)	15,659
Cash at beginning of year	27,378	63,571	47,912
Cash at end of year	$ 43,894	$ 27,378	$ 63,571
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$323,972	$331,828	$329,390
Income taxes	76,519	67,509	[illegible]
Supplemental schedule of noncash investing and financing activities:			
Capital lease obligations incurred	$ 12,500	$ 4,753	$ 10,051
Liability for environmental restoration	15,000	200,000	—

During June 1992, the Company acquired all of the common stock of Syracuse Suburban Gas Company, Inc. in exchange for 353,775 shares of the Company's common stock having a value of $6,120,000.

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 its Canadian energy subsidiary, Opinac Energy Corporation, 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. The results of operations of the Company's oil and gas subsidiary are included in other income and deductions on the Consolidated Statements of Income and Retained Earnings.

Subsidiary oil and gas properties: The Company's Canadian subsidiary owns crude oil and natural gas properties which are accounted for under the full cost method, whereby all costs relating to the exploration for and development of conventional crude oil and natural gas reserves are capitalized. Such costs include land acquisition expenditures, geological and geophysical expenditures and costs of drilling both productive and non-productive wells.

The net book value of oil and gas properties and equipment, less related deferred income taxes, is limited to the sum of the after tax present value of net revenues from proved oil and gas reserves and the lower of cost or fair value of unproved properties. The calculation of future net revenues is based upon prices and costs in effect at the end of the year. Based upon the calculation of the "ceiling test" at December 31, 1991 and March 31, 1992, the Company recorded reserves of approximately $23 million and $21 million, or an after tax effect of $.07 and $.09 per share, respectively. At December 31, 1992, the Company recorded a valuation reserve of $24 million or an after tax effect of $.09 per share in light of a significant decline in previous estimates of proved reserves as indicated by lower than expected production volumes. The net investment in such properties was approximately $101 million and $171 million at December 31, 1992 and 1991, respectively.

The need for additional write-downs during 1993 will be dependent upon future oil and gas prices and on future estimates of reserves. Natural gas prices typically experience a seasonal decline through mid-year, then begin to increase in anticipation of winter demand.

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, 1992 was 9.70%. 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.

In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on 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). Amounts equal to Unit 2's AFC which was no longer accrued have been accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, (each amounting to $239.9 million at December 31, 1992 and 1991) and 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.

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. The total provision for depreciation and amortization, including amounts charged to clearing accounts, was $275.3 million for 1992, $260.2 million for 1991, and $222.1 million for 1990. The percentage relationship between the total provision for depreciation and average depreciable property was 3.3% for 1992, 3.2% for 1991 and 2.9% for 1990. 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.

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 8. "Nuclear Plant Decommissioning.") The amount of accumulated decommissioning costs is reflected in Accumulated Depreciation and Amortization on the Balance Sheet. The annual allowance for Unit 1 and the Company's share of Unit 2 for the years ended December 31, 1992, 1991, and 1990 was approximately $23.1, $23.0, and $4.8 million, respectively.

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 available for sale, 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 practice in 1988 of accruing 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 regulatory agreements, the Company ceased amortizing unbilled revenues as of June 30, 1990. For the year ended December 31, 1990, $17.0 million of such accrued electric revenues are included in the results of operations. At December 31, 1992 and 1991, approximately $77.8 million and $56.5 million, respectively, of unbilled electric revenues remained unrecognized in results of operations and is included in Deferred Credits, and 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 has not been authorized to accrue unbilled gas revenues.

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 defer 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. Thereafter, 100% of the fluctuation to be passed on to ratepayers. The Company also shares with ratepayers fluctuations from amounts forecast for net resale margin and transmission benefits, with the Company retaining/absorbing 20% and passing 80% through to ratepayers.

Beginning in 1991, the Company's rate agreement provides for an electric revenue adjustment mechanism (NERAM) which requires the Company to reconcile actual results to forecast electric public sales gross margin as defined and utilized in establishing rates. Depending on the level of actual sales, a liability to customers is created if sales exceed the forecast and an asset is recorded for a sales shortfall, thereby generally holding recorded electric gross margin to the level forecast in establishing rates. The 1993 rate settlement provides for the operation of the NERAM through December 31, 1993. Recovery or refund of accruals pursuant to the NERAM is accomplished by a surcharge (either plus or minus) to customers over a twelve month period, to begin when cumulative amounts reach certain specified levels.

The 1991 Agreement also includes a Measured Equity Return Incentive Term (MERIT) under which the Company has the opportunity to achieve earnings above its allowed return on equity based on attainment of specified goals associated with its self-assessment process. The MERIT program provides for specific measurement periods and reporting for PSC approval of MERIT earnings. Approved MERIT awards are billed to customers over a period not greater than twelve months. The Company records MERIT earnings when attainment of goals is approved by the PSC or when objectively measured criteria are achieved.

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 accelerated 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. 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 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, 1992, the cumulative amount of undistributed earnings of foreign subsidiaries on which the Company has not provided deferred taxes was approximately $119 million.

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards (SFAS) No. 109 effective for fiscal years beginning after December 15, 1992. This pronouncement will change the way in which income tax expense and liabilities will be calculated and disclosed. The Company has determined that the more significant effects of adopting this pronouncement will be (i) providing deferred taxes for tax benefits flowed through to ratepayers, (ii) adjustment of deferred tax assets and liabilities for enacted changes in tax law or rates and (iii) elimination of net-of-tax accounting. The latter issue would require adjustment of the Company's remaining plant balances that reflect net-of-tax AFC to a pre-tax basis and record the appropriate amount of deferred taxes. On January 15, 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures to Implement SFAS 109 in which it is soliciting comments by April 15, 1993 from interested parties. The Company believes that the SFAS 109 will be considered in the ratesetting process and will therefore not have a significant impact on the Company's results of operations. The Company routinely collects the subsequent increased tax liability from previously flowed-through tax benefits. The Company expects that its total reported assets and liabilities will significantly increase.

The Company estimates that a regulatory asset and a deferred tax liability of about $650 million, due to previously flowed through tax benefits, AFC, and associated revenue requirements, and as reduced by excess deferred taxes and deferred investment tax credits, will be recorded in the Company's financial statements in the first quarter of 1993. Substantially all of the excess deferred taxes relate to property and are not subject to immediate refund to customers.

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 in accordance with PSC directives.

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 from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1992 presentation.

NOTE 2. Bank Credit Arrangements

At December 31, 1992, the Company had $516 million of bank credit arrangements with 19 banks. These credit arrangements consisted of $220 million in commitments under Revolving Credit Agreements (including a Revolving Credit Agreement for HYDRA-CO, Inc., a wholly-owned subsidiary of the Company), $100 million under a Direct Pay Letter of Credit Facility and Revolving Credit Agreement for Oswego Facilities Trust, $40 million in one-year commitments under Credit Agreements, $56 million in lines of credit and $100 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreements extend into 1993 and 1994, 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. In addition to these credit arrangements, the Company obtained $50 million in bank loans which will expire in 1993.

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.

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

	In thousands of dollars	
At December 31:	**1992**	**1991**
Short-term debt:		
Commercial paper	$ 93,248	$ 53,000
Notes payable	104,450	28,500
Bankers acceptances	30,000	49,718
	$227,698	$131,218
Weighted average interest rate (a)	4.33%	6.49%
For Year Ended December 31:		
Daily average outstanding	$110,313	$ 68,852
Monthly weighted average interest rate (a)	4.80%	8.37%
Maximum amount outstanding	$227,698	$131,218
(a) Excluding fees.		

NOTE 3. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1992. 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	$ 88,643	$ 39,698	$ 274
Oswego Steam Station Unit No. 6 (b)	76	$ 275,415	$ 94,203	$ 2,852
Nine Mile Point Nuclear Station Unit No. 2 (c)	41	$1,481,869	$177,140	$18,494

(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 Company then has the option to repurchase its 25% interest in 2004. 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 1,080,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

NOTE 4. 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 s[illegible], $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 1990, 1991 and 1992:

	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*	
January 1, 1990:	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)
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
Issued	—	—	—	—	—	914,005	—	22,850	—
Redemptions			(58,000)	—	(5,800)	(1,481,204)	—	(37,030)	340
Foreign currency translation adjustment									678
December 31, 1991:	136,099,654	136,100	2,490,000	210,000	39,000 *(a)*	11,222,005	80,000	200,550 *(a)*	1,650,312
Issued	1,059,953	1,060	—	—	—	—	—	—	18,401
Redemptions			(78,000)	—	(7,800)	(1,366,000)	—	(34,150)	796
Foreign currency translation adjustment									(11,494)
December 31, 1992:	137,159,607	$137,160	2,412,000	$210,000	$31,200 *(a)*	9,856,005	$80,000	$166,400*(a)*	$1,658,[illegible]

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

The cumulative amount of foreign currency translation adjustment at December 31, 1992 was $(2,771).

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

The Company has certain issues of preferred stock which provide for optional redemption at December 31, as follows:

Series	Shares	1992 (In thousands of dollars)	1991 (In thousands of dollars)	1992 Redemption price per share (Before adding accumulated dividends)	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	102.36	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

e Company has certain issues of preferred stock which provide for mandatory and optional redemption at December 31, lows:

Series	Shares 1992	Shares 1991	In thousands of dollars 1992	In thousands of dollars 1991	Redemption price per share (Before adding accumulated dividends) 1992	Redemption price per share (Before adding accumulated dividends) Eventual minimum
Preferred $100 par value:						
7.45%	312,000	330,000	$ 31,200	$ 33,000	$102.89	$100.00
10.60%	—	60,000	—	6,000	—	—
Preferred $25 par value:						
7.85%	914,005	914,005	22,850	22,850	(a)	25.00
8.375%	600,000	700,000	15,000	17,500	25.55	25.00
8.70%	1,000,000	1,000,000	25,000	25,000	25.75	25.00
8.75%	1,800,000	3,000,000	45,000	75,000	25.75	25.00
9.75%	342,000	408,000	8,550	10,200	25.39	25.00
Adjustable Rate Series B	2,000,000	2,000,000	50,000	50,000	25.75	25.00
			197,600	239,550		
Less sinking fund and redemption requirements			27,200	26,950		
			$170,400	$212,600		

ot redeemable until 1996.

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

The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1993 through 1997 are as follows: $27,200; $27,200; $27,200; $14,150; and $15,120, respectively.

Long-Term Debt

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 2.43% for 1992 and 3.45% for 1991 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.

The $115.7 million of tax-exempt bonds due 2014 will be refinanced at 7.2% during 1994 pursuant to a forward ding agreement entered into in 1992.

es Payable include a ten-year Swiss franc bond issue alent 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 arrangements with the Oswego Facilities Trust (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 1992 consists of obligations under capital leases of approximately $53.2 million (See Note 9. "Lease Commitments"), a liability to the U.S. Department of Energy for nuclear fuel disposal of approximately $90.6 million (See Note 8. "Nuclear Fuel Disposal Costs") and a liability for contract termination of approximately $14 million.

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, 1992, including mandatory sinking fund redemption requirements of approximately $2-3 million per year excluding capital leases are approximately $35 million, $319 million, $68 million, $58 million and $43 million, respectively.

Long-term debt at December 31, consisted of the following:

Series	Due	In thousands of dollars 1992	1991
First mortgage bonds:			
12.68% - 13.06%	1992	$ —	$ 100,000
8 7/8%	1994	150,000	150,000
4 5/8%	1994	40,000	40,000
**9 1/8%	1996	—	100,000
5 7/8%	1996	45,000	45,000
**9 5/8%	1997	—	100,000
6 1/4%	1997	40,000	40,000
9 7/8%	1998	200,000	200,000
6 1/2%	1998	60,000	60,000
10 1/4%	1999	100,000	100,000
10 3/8%	1999	100,000	100,000
**9 1/8%	1999	—	75,000
9 1/2%	2000	150,000	150,000
7 3/8%	2001	65,000	65,000
9 1/4%	2001	100,000	100,000
7 5/8%	2002	80,000	80,000
7 3/4%	2002	80,000	80,000
7 3/8%	2003	220,000	—
8 1/4%	2003	80,000	80,000
**9 1/2%	2003	—	35,295
8%	2004	300,000	—
**9.95%	2004	—	55,000
9 3/4%	2005	150,000	150,000
**10.20%	2005	—	23,000
8.35%	2007	66,640	66,640
8 5/8%	2007	30,000	32,000
*6 5/8%	2013	45,600	45,600
*11 1/4%	2014	75,690	75,690
*11 3/8%	2014	40,015	40,015
**10%	2016	—	150,000
**10%	2016	—	100,000
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	—
8 1/2%	2023	165,000	—
*8 7/8%	2025	75,000	75,000
Total First Mortgage Bonds		2,757,945	2,663,240
Promissory notes:			
*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 1993-2004		87,700	144,200
Swiss Franc Bonds due December 15, 1995		50,000	50,000
Oswego Facilities Trust		90,000	96,350
Other		157,829	135,688
Unamortized premium (discount)		(8,453)	(2,709)
TOTAL LONG-TERM DEBT		3,548,781	3,500,529
Less long-term debt due within one year		57,722	175,501
		$3,491,059	$3,325,028

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

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 certificati[illegible] additional property, the waiver of the issuance of addi[illegible] bonds or the retirement of outstanding bonds. The 1992 requirements for these series were satisfied by the certification of additional property. The Company anticipates that the 1993 requirements for these series will be satisfied by means other than payment in cash. Total annual debt retirement fund requirements for these series, based upon mortgage bonds outstanding at December 31, 1992, are $4.9 million.

NOTE 5. Disclosures about Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and short-term investments: The carrying amount approximates fair value because of the short maturity of the financial instruments.

Long-term investments: The carrying value and market value are not material to the financial statements.

Mandatorily redeemable preferred stock: Fair value of the mandatorily redeemable preferred stock has been [illegible] mined by one of the Company's brokers or estimat[illegible] management based on discounted cash flows.

Long-term debt: The fair value of the Company's long-term debt has been estimated by one of the Company's brokers. The carrying value of NYSERDA bonds, the Oswego Facilities Trust and other long-term debt are considered to approximate fair value.

The estimated fair values of the Company's financial instruments are as follows:

	December 31, 1992 In thousands of dollars Carrying Amount	Fair Value
Cash and short-term investments	$ 43,894	$ 43,894
Mandatorily redeemable preferred stock	197,600	199,114
Long-term debt:		
First Mortgage Bonds	2,757,945	2,888,022
Medium Term Notes	87,700	93,890
NYSERDA bonds	413,760	413,760
Swiss Franc Bonds	50,000	62,374
Other	104,665	104,665
Oswego Facilities Trust	90,000	90,000

NOTE 6. Federal and Foreign Income Taxes

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1992	1991	1990
United States	$410,283	$394,596	$141,129
Foreign	18,394	(6,252)	19,861
Consolidating eliminations	(16,741)	(11,080)	(16,993)
Income before income taxes	$411,936	$377,264	$143,997

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		
	1992	1991	1990
Components of Federal and foreign income taxes:			
Current tax expense: Federal	$119,929	$ 75,452	$121,275
Foreign	915	597	(2,495)
	120,844	76,049	118,780
Deferred tax expense: Federal	54,858	74,983	(8,096)
Foreign	7,531	7,105	10,430
	62,389	82,088	2,334
Income taxes included in Operating Expenses	183,233	158,137	121,114
Current Federal income tax credits included in Other Income and Deductions	(31,787)	(24,734)	(32,756)
Deferred Federal and foreign income tax expense (credits) included in Other Income and Deductions	4,058	492	(27,239)
Total	$155,504	$133,895	$ 61,119
Components of deferred Federal and foreign income taxes *(Note 1)*:			
Depreciation related	$ 78,467	$ 90,897	$ 84,591
Investment tax credit	(8,067)	(8,137)	(4,014)
Alternative minimum tax	(1,197)	(27,276)	(16,843)
Construction overheads	(1,798)	(1,066)	(10,324)
Recoverable energy and purchased gas costs	(1,926)	8,066	(27,897)
Unbilled revenues	(2,600)	(3,097)	(13,898)
Deferred operating expenses	10,867	(2,179)	24,146
Deferred transmission revenues	—	6,601	(6,569)
Nuclear settlement disallowance	20,099	12,865	(32,964)
Reserve for NM Uranium, Inc.	(390)	(512)	(5,013)
MERIT recovery	(4,263)	9,935	—
Electric revenue adjustment mechanism	(1,248)	6,859	(1,669)
Opinac reserve for oil and gas properties	(19,706)	(13,083)	—
Bond reacquisition premium	7,379	—	—
Other	(9,170)	2,707	(14,451)
Deferred Federal income taxes (net)	$ 66,447	$ 82,580	$ (24,905)
Reconciliation between Federal and foreign income taxes and the computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	$140,058	$128,270	$ 48,959
Reduction (increase) attributable to flow-through of certain tax adjustments:			
Depreciation	(37,543)	(36,440)	(30,569)
Allowance for funds used during construction	11,205	7,540	8,728
Deferred investment tax credit amortization	8,024	7,891	7,820
Other	2,868	15,384	1,861
	(15,446)	(5,625)	(12,160)
Federal and foreign income taxes	$155,504	$133,895	$ 61,119

NOTE 7. 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 $23.2 million for 1992, $23.9 million for 1991 and $22.8 million for 1990 (of which $6.2 million for 1992, $6.0 million for 1991 and $5.5 million for 1990 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. No contribution was made to the pension plan during 1991 and 1990. 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.

In both 1992 and 1991, the discount rate and rate of increase in future compensation levels used in determining the actuarial present value of the projected benefit obligations were 8.25% and 4.25% (plus merit increases), respectively. The expected long-term rate of return on plan assets was 9.00% in 1992 and 1991.

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 comp[illegible] whose charges and premiums are based on the claim[illegible] during the year. The cost of providing these benefi[illegible] retired employees are provided for in rates and amounted to approximately $16.7 million for 1992, $15.0 million for 1991 and $14.9 million for 1990.

In December 1990, the FASB issued SFAS No. 106 entitled "Employers' Accounting for Postretirement Benefits Other Than Pensions." This Statement, which the Company will adopt for 1993, requires accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. The Company presently 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 to be approximately $409 million at January 1, 1993 based upon health care cost trend rates of 14% trending down to 6% and assuming a long-term discount rate of 8%. The annual cost will be approximately $66 million and includes amortization of the transition amount related to prior service over a twenty year period. On January 27, 1993, the PSC approved a rate settlement plan which included an incremental allowance for postretirement benefits of approximately $12 million including capital portion. The difference in the postretirement benefit annual expense compared with the rate allowance (approximately $31 million) will be deferred.

The PSC is expected to issue a Statement of Policy regard-

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

	In thousands of dollars		
At December 31,	1992	1991	1990
Service cost — benefits earned during the period	$ 27,100	$ 27,000	$ 25,700
Interest cost on projected benefit obligation	48,800	43,500	39,100
Actual return on Plan assets	(59,600)	(116,600)	(7;500)
Net amortization and deferral	6,900	70,000	(34,500)
Net pension cost	$ 23,200	$ 23,900	$ 22,800

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,	1992	1991
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$419,582	$341,697
Non-vested benefits	46,563	4,026
Accumulated benefit obligations	466,145	345,723
Additional amounts related to projected pay increases	193,630	229,524
Projected benefits obligation for service rendered to date	659,775	575,247
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	796,843	721,132
Plan assets in excess of projected benefit obligations	137,068	145,885
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	35,184	37,977
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	(174,713)	(187,266)
Prior service cost not yet recognized in net periodic pension cost	36,092	36,281
Prepaid pension costs included in current assets	$ 33,631	$ 32,877

ing the accounting for pension and postretirement benefit ... With respect to postretirement benefits, the PSC ... proposal recommended a transition to full accrual in ... over a period not to exceed five years, with recovery of any resultant deferrals over a period of ten years from the year of adoption. The Company can provide no assurance that the Statement of Policy as ultimately approved by the PSC will be consistent with the PSC Staff's proposal.

The Emerging Issues Task Force (EITF) recently issued a consensus position permitting utilities to record a regulatory asset for differences between allowances in rates and full accrual of postretirement benefits when such deferral is pursuant to a ratemaking plan that provides for a transition to full accrual in rates within five years and recovery of deferrals within twenty years of adoption. The Company believes that PSC Staff's proposal meets the EITF consensus position.

In November 1992, the FASB issued SFAS No. 112 "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement requires employers to recognize the obligation to provide postemployment benefits if the obligation is attributable to employees' services already rendered, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. The adoption of the requirements of this Statement are not expected to significantly impact the Company's financial condition or results of operations. Any impact of the State- ... should be addressed in the ratesetting environment.

NOTE 8. Nuclear Operations

Unit 1 Economic Study: Under the terms of the 1989 Agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Unit 1, prior to the start of the next two refueling outages. The first report, which recommended continued operation of Unit 1 over the remaining term of its license (2009), was filed with the PSC in March 1990.

On November 20, 1992 the Company submitted to the PSC an updated economic analysis which indicated that Unit 1 can be expected to provide value to customers and shareholders through its next fuel cycle, which will end in early 1995. The study also indicated that the Unit could continue to provide benefits for the full term of its license if operating costs can be reduced and generating output improved above the historical average. The Company is aware of only one formal response to its study, from IPPNY, which claims that continued operation of Unit 1 is uneconomic. The Company believes the findings of IPPNY to be flawed.

The study analyzed a number of scenarios resulting in break-even capacity factors, ranging from 44% to 122%. The "base" case assumes a capacity factor of 61%, which is consistent with the target reflected in the Unit 1 operating ...ive mechanism, and also future operating and capital ...lightly lower than historical performance. While a marginal benefit would be realized from operating the Unit for at least the next two years (one fuel cycle), there would be a negative net present value in excess of $100 million if the Unit were to be operated over its remaining 17-year license period. Under an "improved performance case," the Unit is assumed to operate at a 70% capacity factor with future operating and capital costs consistent with average industry performance. The Company believes these goals are achievable for Unit 1. The "improved performance case" results in positive net present value in excess of $100 million if the Unit is operated over its remaining life. Such results are indicative of the volatility of the assumptions and uncertainties involved in developing the Unit's economic forecast.

The study necessarily relies on a number of significant assumptions which are subject to uncertainty and could produce a wide range of outcomes. These assumptions include the Unit's capacity factor, levels of operating and capital costs, anticipated demand for electricity, anticipated supply of electricity including NUG power, implementation and compliance costs of the 1990 Clean Air Act and other federal and state environmental initiatives, and fuel availability and prices, especially natural gas. Given the potential for rapid and substantial change in any or all of these assumptions, the Company will be developing operational and external measures intended to initiate a prompt periodic reassessment of the economic viability of the Unit.

An agreement with the PSC allows recovery of all reasonable and prudently-incurred sunk costs and costs of retirement, should a prudent decision be made to retire Unit 1 before early 1995. All parties to the 1991 Agreement reserved the right to petition the PSC to institute a formal investigation to review the prudence of any Company decision to retire Unit 1. Any such decision by the Company will be made in consultation with governmental and regulatory authorities.

The Company's net investment in Unit 1 is approximately $600 million. Based upon the Company's 1989 study, the cost of decommissioning Unit 1 is estimated to be approximately $248 million in 1992 dollars. An update of the study is currently underway as part of the formal decommissioning plan discussed above. The Company has collected $75.9 million in rates through 1992, of which $43.1 million has been deposited in an external trust, which has accumulated a balance of $46.4 million including earnings on fund investments.

Unit 1 Status: Unit 1 will be taken out of service in mid-February 1993 for an eight week refueling outage.

In an August 1992 Safety Evaluation Report, the Nuclear Regulatory Commission (NRC) confirmed the Company's assessment that Unit 1 could operate until at least 2007 without making modifications to the plant's torus. The torus, a large donut-shaped structure located below the reactor, is half filled with water. It is a suppressive pool designed to relieve pressure from the plant's reactor by converting excess steam to water.

In November, the Company requested that the NRC re-review the assessment to insure that the evaluation of the torus performed by the NRC was consistent with the Company's methodology. In the interim, the Company continues to monitor the torus wall thickness in accordance with code requirements to ensure corrosion rates do not exceed anticipated levels. The NRC has stated that it could take up to twelve months to complete its re-review.

Thickness measurements for the entire torus were performed in January 1993. Preliminary results indicate that wall thickness continues to meet code requirements. Measurements of selected areas of the torus will be performed biannually.

Unit 2 Status: Two cracked low pressure turbine rotor blade/wheel assemblies were removed during the last refueling outage. As a result, the output of Unit 2 has been reduced by 3% or approximately 37 MW. The next refueling outage is scheduled to begin in September 1993.

Nuclear Plant Decommissioning: Based on a 1989 study, the cost of decommissioning Unit 1, which is expected to begin in the year 2009, is estimated by the Company to be approximately $548 million at that time ($248 million in 1992 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 $535 million ($105 million in 1992 dollars). The annual decommissioning allowance reflected in ratemaking is based upon these estimates. Through December 31, 1992, the Company has recovered approximately $86.6 million of decommissioning costs in rates and $3.9 million in earnings on the decommissioning trusts for both units. The Company continues to review the estimated requirements for decommissioning and plans to seek rate adjustments when appropriate. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that decommissioning costs, if higher than currently estimated, will ultimately be recovered in the rate process.

The NRC issued regulations in 1988 requiring owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning activities of contaminated portions of nuclear facilities as well as establishing 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 regulations, the Company has estimated that the minimum funding requirements for Unit 1 and its share of Unit 2, respectively, will be $364 million and $381 million in future dollars. As of December 31, 1992, the Company has accumulated in an external trust $46.4 million for Unit 1 and $10.5 million for its share of Unit 2, which are included in Other Property and Investments. In 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: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

In August 1988, the Price-Anderson Amendments Act of 1988 (the Act) was enacted, which significantly increased the statutory liability limits for the protection of the public. With respect to a nuclear incident at a licensed reactor, the statutory limit, which is in excess of the $200 million of nuclear liability insurance, was increased from $710 million to approximately $7.5 billion. This limit is funded by assessments of up to $63 million for each of the 115 presently licensed nuclear reactors in the United States, payab[illegible] a rate not to exceed $10 million per reactor per yea[illegible] assessments are subject to periodic inflation indexin[illegible]d 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 serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations whether or not a nuclear incident actually occurs.

The Act was extended for 15 years with a renewal date of August 15, 2002.

Nuclear Property Insurance: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the Nuclear Insurance Pools (ANI/MRP). In addition, there is $765 million in excess of the $500 million primary nuclear insurance with the Nuclear Insurance Pools (ANI/MRP) and $1.325 billion, which is also in excess of the $500 million primary and the $765 million excess nuclear insurance, with Nuclear Electric Insurance Limited (NEIL). The total nuclear property insurance is $2.59 billion.

NEIL is a utility industry-owned mutual insurance company chartered in Bermuda with offices in the United States. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement [illegible]r during prolonged accidental outages. The insuran[illegible]vides coverage for outages for 156 weeks after a 21[illegible]k waiting period.

NEIL insurance is subject to retrospective premium adjustment for which the Company could be assessed up to approximately $12.4 million per loss.

Low Level Radioactive Waste: The Federal Low Level Radioactive Waste Policy Act as amended in 1985 required states to join compacts or individually develop their own low level radioactive waste burial site. In response to the Federal law, New York State decided to develop its own site because of the large volume of low level radioactive waste it generates.

New York State has narrowed its selection for potential low level radioactive waste disposal sites to five locations in Cortland and Allegheny counties.

On January 1, 1990, Governor Cuomo certified that all of New York State's low level radioactive waste would be managed by January 1, 1993. This certification contained a plan of how the low level radioactive waste will be managed in New York State until a disposal facility is available. Due to public opposition and the need to reevaluate the disposal siting process, the January 1, 1993 date was not attained. Currently, an extension of access to the Barnwell, South Carolina waste disposal facility was made available to out-of-region low level radioactive waste generators by the state of South Carolina, and New York State has elected to [illegible]s option through June 30, 1994.

The State's management plan includes developme[illegible] of interim storage capability for non-utility waste generators and assumes that such facilities should plan for as long as 10 years of interim storage. A low level radioactive waste management program and contingency plan is under way so that Unit 1 and Unit 2 will be prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period, if required.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (Act) was passed into law. The Act established a cost of $.001 per kilowatt-hour of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until 1998, the year in which the Company had initially planned to ship irradiated fuel to an approved DOE disposal facility. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 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.

The Energy Policy Act of 1992 provides for the establishment of a federal decontamination and decommissioning fund to provide for the clean up of DOE uranium processing facilities, funded in part by nuclear utilities. The Company estimates that it has about a $25 million liability to this fund based on prior DOE nuclear fuel processing services received. This amount has been accrued at December 31, 1992 and is expected to be recovered as a fuel expense as provided by the Act. The liability is payable over 15 years and annual assessments will be indexed for inflation.

NOTE 9. Commitments and Contingencies

Long-term Contracts for the Purchase of Electric Power: At January 1, 1993, 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	928,000	$19,320,000
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	67,000(a)	10,242,000
		1,369,000	$38,262,000

(a) *50,000 kw for summer of 1993; 72,000 kw for winter of 1993-94.*

The purchase capacities shown below 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 was approximately $64.4 million, $61.2 million and $57.2 million for the years 1992, 1991 and 1990, respectively.

Under the requirements of the Federal Public Utility Regulatory Policies Act of 1978, the Company is required to purchase power generated by NUGs, as defined therein. Approximately $543 million and $268 million was paid to NUGs in 1992 and 1991 for 8,632,000 mwhrs and 4,303,000 mwhrs of energy and associated capacity, respectively. Through December 31, 1992, the Company has entered into agreements with numerous current and prospective independent producers, including NUGs which, has substantially increased its future purchase power commitments. The amount of the commitment and the available capacity are dependent upon the completion of these projects. Based upon contracts entered into and approved to date, the Company estimates that it will be obligated to purchase power generated by facilities having an aggregate amount of capacity in each of the following periods: 2,226 MW in 1993, 2,309 MW in 1994, 2,651 MW in 1995 and 2,651 MW in 1996. By 1995, the Company will be paying $1.2 billion a year for 2,651 MW of capacity. Generally, the Company must only pay for energy delivered.

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 1993 through 1997 will require approximately $2.28 billion, excluding AFC, nuclear fuel and certain overheads capitalized. For the years 1993 through 1997, the estimates are $412 million, $504 million, $458 million, $457 million and $446 million, respectively. These amounts are reviewed by management as circumstances dictate.

Lease Commitments: The Company leases certain property and equipment which meet the accounting criteria for capitalization. Such leases, having a net book value of $53.2 million and $48.3 million at December 31, 1992 and 1991, 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 $473 million, a substantial portion of which relates to a transmission line facility with an unelapsed term of 34 years. Annual future minimum rental commitments for the period 1993-1997 range between $23 million and $28 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, 1992 and 1991 respectively, $200 million of receivables had been sold under this agreement. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect the receivables sold from bad debts. To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. 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.

Anti-trust Action: In 1987, Long Lake Energy Corporation (Long Lake) filed an action asserting claims under Section 2 of the Sherman Act and New York's Donnelly Act which alleged that the Company interfered with Long Lake's attempts to license hydro-electric projects with the FERC. On June 26, 1992 the Company entered into an Agreement with Adirondack Hydro Development Corporation (AHDC), which in turn completed an acquisition of certain assets of Long Lake. The Agreement between the Company and AHDC provided for the dismissal of the anti-trust case, as well as a lease transaction and long-term power purchase contract between the Company and AHDC. The Company incurred no loss as a result of the resolution of this matter.

Environmental Issues: The public utility industry typically utilizes and/or generates in its operations a broad range of potentially hazardous products and by-products. These products or by-products may not have previously been considered hazardous, and may not be considered hazardous currently, but may be identified as such by Federal, state or local authorities in the future. The Company believes it is handling identified products and by-products in a manner consistent with Federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and assure compliance with such requirements. The Company is also currently conducting a program to investigate and restore, as necessary to meet current environmental standards, certain properties associated with its 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 as to which it may be determined that the Company contributed. The Company has been advised that various Federal, state or local agencies currently believe that certain properties require investigation and is in the process of classifying many of these sites based on available information to enhance management of investigation and remediation, if determined to be necessary.

The Company is aware of 84 sites with which it has been or may be associated, including 42 which are Company-owned. The Company-owned sites include 24 coal gasification sites (MGP), 14 industrial waste sites and 4 operating property sites where corrective actions are deemed necessary to prevent, contain and/or remediate contamination of soil and/or water in the vicinity. Of these Company-owned sites, 12 are listed on the New York State Registry of Inactive Hazardous Waste Sites and 1, Saratoga Springs is on the Federal National Priorities List (NPL). The 42 remaining sites with which the Company has been or may be associated are generally industrial waste sites as to which the Company is alleged to be a Potentially Responsible Party (PRP) and may be required to contribute some proportionate share towards investigation and clean-up. Additional sites with which the Company has been or may be associated could be identified in the future as requiring investigation or remediation.

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, (3) if necessary, determine the appropriate remedial actions required for site restoration and (4) where appropriate, identification of other parties whom should bear some, if not all, of the cost of remediation. Legal action against such other parties, if necessary, will be initiated. After site investigations have been completed, the Company expects to be able to determine site-specific remedial actions necessary and to estimate the attendant costs for restoration. However, since technologies are still developing and the Company has not yet undertaken any full-scale remedial actions following Environmental Protection Agency (EPA) requirements at any identified sites, nor have any detailed remedial designs been prepared or submitted to appropriate regulatory agencies, the ultimate cost of remedial actions may change substantially as investigation and remediation progress.

The Company has determined that it is probable that 35 of the 42 owned sites will require some degree of investigation, remediation and monitoring. This conclusion is based upon a number of factors, including the nature of the identified contaminants, the location and size of the site, the proximity of the site to sensitive resources, the status of regu-

NPL Site Name	New York State County	Number of Known PRPs	Total Estimated Cost (Millions)	Company's Estimated Potential Contribution Factor (%)
Clothier Disposal	Oswego	31	$ 3	.06
Fulton Terminals	Oswego	105	4	.28
Johnstown City Landfill	Fulton	130	32	.76
Pollution Abatement Services	Oswego	105	13	.18
Rosen Brothers Scrap Yard/Dump	Cortland	5	32	20.00
Sealand Restoration Site	St. Lawrence	22	32	1.00
Volney Municipal Landfill (PAS)	Oswego	105	15	.18
York Oil Co.	Franklin	20	15	5.00
Quanta Resources	Onondaga	25	2	4.00
Volney Municipal Landfill	Oswego	unknown	32	unknown
Bern Metal Co., Inc.	Erie	unknown	32	unknown
Onondaga Drum Site	Onondaga	unknown	32	unknown

latory investigation and knowledge of activities at similarly situated sites. Although the Company has not extensively investigated many of those sites, it has sufficient information to estimate a range of cost of investigation and remediation. As a consequence of a preliminary site characterization process completed to date, the Company has accrued a liability of $195 million for these owned sites, representing the low end of the range of cost for investigation and remediation. The high end of the range is estimated at approximately $514 million.

In 1991, the Company completed an Interim Remedial Measures (IRM) initiative at one of its coal gasification sites that was on the New York State Registry. This IRM was the first test effort in a Company program intended to remove or control waste sources from sites in an effort to eliminate potential threats to human health and the environment, including the cessation of any associated spread of contaminants from the site. The cost of the IRM as applied to the first site was approximately $3 million, exclusive of ongoing monitoring costs. This particular site was removed from the New York State Registry in October 1991.

The results of this first IRM effort have provided a basis for the Company to further develop and propose a plan to apply the IRM concept at other qualifying sites. The Company and the New York State Department of Environmental Conservation (DEC) have executed an Order of Consent providing for an investigation and remediation program for 21 former MGP sites. The program provides for a ten-year schedule of investigation and remediation activities. The Company's 1993 rate settlement includes the estimated costs of the first year of this program. The Company believes that this proactive approach may allow for more timely and economic removal or control of wastes than application of regulatory enforcement actions.

The Company does not currently believe that a clean-up will be required at the 7 remaining Company-owned sites, although some degree of investigation of these sites is included in its investigation and remediation program.

With respect to the 42 sites with which the Company has been or may be associated as a PRP, 26 are included in the New York State Registry of Inactive Hazardous Waste Sites and 15 are on the NPL or are under evaluation for listing. The Company has reached agreement with regulatory agencies and other PRP's and settled on 7 of these sites through December 31, 1992, in an aggregate amount that is immaterial to the Company. Total costs to investigate and remediate the remaining 35 with which the Company is associated are estimated to be approximately $492 million. The Company estimates its share of this total at approximately $20 million and this amount has been accrued at December 31, 1992.

Of the 15 PRP sites on the NPL for Uncontrolled Hazardous Waste Sites as published by the EPA in the Federal Register, one (Ludlow Landfill) has been settled by the Company for less than $10,000 and 12 are listed on page 46. The remaining two are further discussed below.

Estimates of the Company's potential liability for PRP sites are derived by estimating the total cost of clean-up of the sites and then applying the related Company contribution factor to that estimate. Estimates of the total clean-up costs are determined by using the Company's investigation to date, if any, discussions with other PRPs and, where no information is known at the time of estimate, EPA estimates based on average costs disclosed in the Federal Register of September 25, 1991. The contribution factor is calculated using either the Company's percentage share of the total PRPs named, which assumes all PRPs will contribute equally, or the percentage agreed upon with other PRPs through a steering committee or by other means. Actual Company expenditures for these sites are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility in certain of these PRP sites and is contesting liability accordingly.

In November 1989, an action was commenced against the Company and six other corporations by the U.S. Department of Justice in Federal Court pursuant to the Comprehensive Environmental Response, Compensation and Liability Act. The complaint alleges that the defendants are liable for past response costs of $2.3 million and additional ongoing and future response costs incurred by the EPA in investigating and remediating PCB contamination at the Wide Beach Development Site in Erie County, New York. The Company has reached a monetary settlement, at less than $300,000, with the Department of Justice and the other defendants which dismisses the Company from the proceeding. An Order on Consent incorporating the settlement terms has been entered with the court in January 1993 releasing the Company from further liability from this action.

The EPA advised the Company by letter that it is one of 833 PRPs under Superfund for the investigation and clean-up of the Maxey Flats Nuclear Disposal Site in Morehead, Kentucky. The Company has contributed to a study of this site and estimates that the cost to the Company for its share of investigation and remediation based on its contribution factor of 1.3% would approximate $1 million.

The Company believes that costs incurred in the investigation and restoration process for both Company owned sites and sites with which it is associated will be recoverable in the ratesetting process. Rate Agreements since 1991 provide for recovery of anticipated investigation and remediation expenditures, however, the PSC Staff reserves the right to review the appropriateness of the costs incurred. No costs have been challenged to date by the PSC Staff. The Company's 1993 rate settlement includes $35 million for site investigation and remediation, a substantial increase from amounts authorized under the 1991 Agreement and reflecting implementation of the IRM initiative. Based upon management's assessments that remediation costs will be recovered from ratepayers, a regulatory asset has been recorded representing the future recovery of remediation obligations accrued to date.

The Company also agreed in the 1991 Agreement to a cost sharing arrangement with respect to one industrial waste site. The Company does not believe that this cost sharing agreement, as it relates to this one industrial waste site, will have a material effect on the Company's financial position or results of operations.

The Company is also in the process of providing notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant and industrial waste sites. The Company is unable to predict whether such insurance claims will be successful.

Tax assessments: The Internal Revenue Service (IRS) is currently conducting an examination of the Company's Federal income tax returns for the years 1987 and 1988 and has submitted a Revenue Agents Report to the Company. The IRS has proposed various adjustments to the Company's federal income tax liability for these years which could increase the Federal income tax liability by approximately $83 million before assessment of penalties and interest. Included in these proposed adjustments are several potentially significant issues involving Unit 2. These issues include its tax in-service date, cost basis for investment tax credit purposes, partnership short year for depreciation purposes and a proposed reclassification of plant costs to "licensing costs," an intangible asset. The Company is vigorously defending its position on each of these issues. Pursuant to the 1990 Unit 2 settlement, to the extent the IRS is able to sustain disallowances in those areas, the Company will have to absorb a portion of any disallowance which it believes will not have a material impact on the Company's financial position.

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

FERC Order 636: In April 1992, the FERC issued Order 636, which will require interstate pipelines that offer open access transportation services to unbundle pipeline sales services from pipeline transportation service. These changes will enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as arrange for transportation and gas storage services.

As a result of these structural changes, pipelines face "transition" costs from implementation of the order. The principal costs are: unrecovered gas cost that would otherwise have been billable to pipeline customers under previously existing rules, costs related to restructuring existing gas supply contracts and costs of assets needed to implement the order (such as meters, valves, etc.). Under the Order, pipelines are allowed to recover 100% of prudently incurred costs from customers. Prudence will be determined by the FERC review.

The amount of restructuring costs that may be billable to the Company will be determined in accordance with pipeline restructuring plans which have been submitted to FERC for approval. There are four pipelines to which the Company may have some liability. The Company is actively participating in FERC hearings on these matters, to ensure an equitable allocation of costs. Based upon information presently available to the Company from the petitions filed by the pipelines and the Company's participation in settlement negotiations, its liability for the pipelines' unrecovered gas costs could be as much as $56 million and its liability for pipeline restructuring costs could be as much as $60 million. However, the Company believes its ultimate liability will be less than $64 million in total, based on its assessment of the progress of settlement negotiations. The Company anticipates these costs will be primarily reflected in demand charges paid to reserve space on the various interstate pipelines and will be billed over a period of approximately 7 years, with billings more heavily weighted to the first 3 years. The Company is unable to predict the probable outcome of current pipeline restructuring settlements and the amounts for which it may be ultimately liable or the period over which this liability will be billed. The Company believes any amounts for which it is ultimately determined to be liable will be recoverable in the ratesetting process.

NOTE 10. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income (loss) and earnings (loss) per common share by quarters from 1992, 1991 and 1990, respectively, 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, 1992	$ 963,629	$119,181	$ 41,835	$ .24
1991	848,593	117,139	35,111	.18
1990	781,270	63,531	(104,807)	(.85)
September 30, 1992	$ 822,530	$ 89,658	$ 40,401	$ .23
1991	734,446	102,627	40,783	.23
1990	682,114	128,191	60,128	.37
June 30, 1992	$ 881,427	$137,515	$ 71,734	$ .46
1991	807,024	127,159	57,691	.35
1990	737,860	103,750	35,756	.18
March 31, 1992	$1,033,941	$177,972	$102,462	$ .68
1991	992,455	178,509	109,784	.73
1990	953,475	156,589	91,801	.60

In the second quarter of 1992 and the third quarter of 1991, the Company recorded $22.8 million ($.11 per common share) [illegible]30 million ($.14 per common share), respectively, for MERIT earned in accordance with the 1991 Agreement. In the first [illegible]r of 1992 and the fourth quarter of 1992 and 1991, the Company recorded $21 million ($.09 per common share), $24 million ($.09 per common share) and $23 million ($.07 per common share), respectively, to write-down its subsidiary investment in oil and gas properties.

In the fourth quarter of 1991 and 1990, the Company accrued $3 million ($.01 per common share) and $15 million ($.07 per common share), respectively, relating to its investment in NM Uranium, Inc., resulting in a decrease in net income for each quarter. 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.

NOTE 11. 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		
	1992	1991	1990
Operating revenues:			
Electric	$3,147,676	$2,907,293	$2,669,308
Gas	553,851	475,225	485,411
Total	$3,701,527	$3,382,518	$3,154,719
Operating income before taxes:			
Electric	$ 645,696	$ 644,084	$ 522,947
Gas	61,863	39,487	50,228
Total	$ 707,559	$ 683,571	$ 573,175
Pretax operating income, including AFC:			
Electric	$ 666,269	$ 662,258	$ 543,504
Gas	62,721	40,244	51,085
Total	728,990	702,502	594,589
Income taxes, included in operating expenses:			
Electric	176,901	152,840	119,185
Gas	6,332	5,297	1,929
Total	183,233	158,137	121,114
Other (income) and deductions	(11,391)	(10,643)	71,728
Interest charges	300,716	311,639	318,869
Net income	$ 256,432	$ 243,369	$ 82,878
Depreciation and amortization:			
Electric	$ 255,256	$ 240,887	$ 204,417
Gas	18,834	17,929	16,440
Total	$ 274,090	$ 258,816	$ 220,857
Construction expenditures:			
(including nuclear fuel):			
Electric	$ 442,741	$ 445,298	$ 373,232
Gas	59,503	77,176	58,347
Total	$ 502,244	$ 522,474	$ 431,579
Identifiable assets:			
Electric	$7,000,659	$6,760,375	$6,435,401
Gas	783,766	725,553	610,648
Total	7,784,425	7,485,928	7,046,049
Corporate assets	806,110	755,548	719,357
Total assets	$8,590,535	$8,241,476	$7,765,406

Market Price of Common Stock and Related Stockholder Matters

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

Preferred dividends were paid on March 31, June 30, September 30 and December 31. Common stock dividends were paid on February 29, May 31, August 31 and November 30. The Company presently estimates that none of the 1992 common or 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:

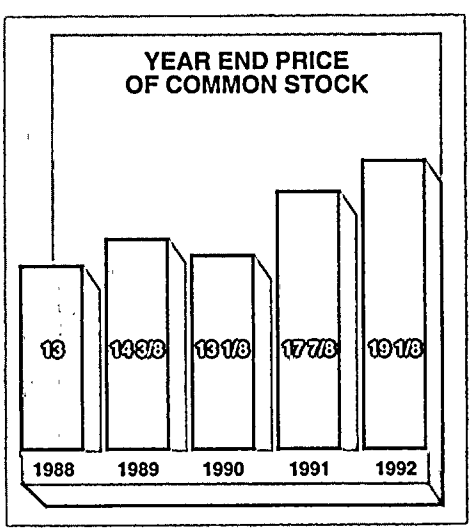
1992	Dividends Paid Per Share	Price Range High	Price Range Low
1st Quarter	**$.16**	**$19**	**$17⅜**
2nd Quarter	**.20**	**19¼**	**17½**
3rd Quarter	**.20**	**20½**	**18⅞**
4th Quarter	**.20**	**19⅞**	**18⅜**
1991			
1st Quarter	—	$15	$12¾
2nd Quarter	—	15⅞	14¼
3rd Quarter	$.16	17	15¼
4th Quarter	.16	18	16¾

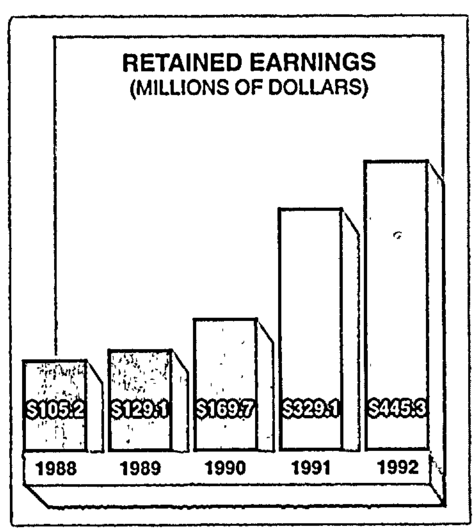
Other Stockholder Matters: The holders of Common Stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on Preferred Stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon 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 aside 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 115,000 stockholders owned common shares of the Company and about 5,300 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	44,910	1,466,395
100 to 999	62,931	17,440,068
1,000 or more	7,107	118,253,144
	114,948	137,159,607

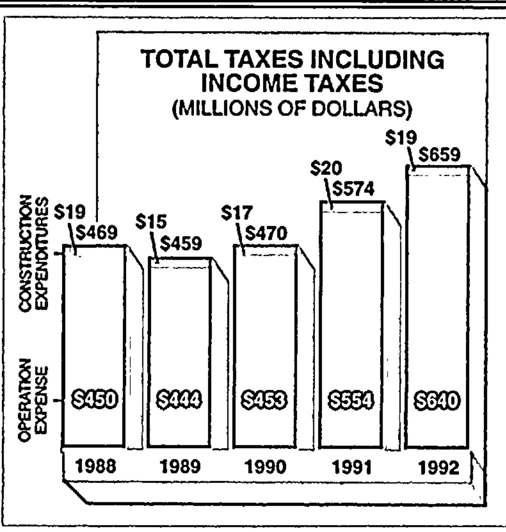


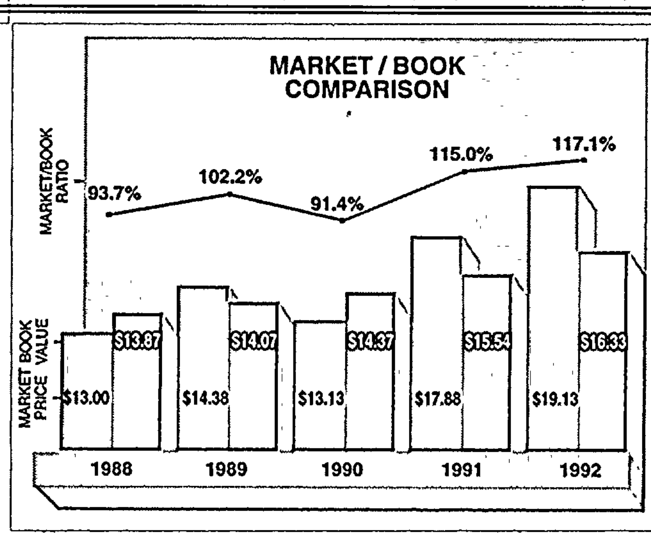


Selected Financial Data

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.

	1992	1991	1990	1989	1988
Operations: (000's)					
Operating revenues	$3,701,527	$3,382,518	$3,154,719	$2,906,043	$2,800,453
Net income	256,432	243,369	82,878	150,783	208,814
Common stock data:					
Book value per share at year end	$16.33	$15.54	$14.37	$14.07	$13.87
Market price at year end	19 1/8	17 7/8	13 1/8	14 3/8	13
Ratio of market price to book value at year end	117.1%	115.0%	91.4%	102.2%	93.7%
Dividend yield at year end	4.2%	3.6%	0.0%	0.0%	9.2%
Earnings per average common share	$ 1.61	$ 1.49	$ .30	$ .78	$ 1.21
Rate of return on common equity	10.1%	10.0%	2.1%	5.6%	8.7%
Dividends paid per common share	$ .76	$ .32	$ .00	$ .60	$ 1.20
Dividend payout ratio	47.2%	21.5%	0.0%	76.9%	99.2%
Capitalization: (000's)					
Common equity	$2,240,441	$2,115,542	$1,955,118	$1,914,531	$1,881,394
Non-redeemable preferred stock	290,000	290,000	290,000	290,000	290,000
Redeemable preferred stock	170,400	212,600	241,550	267,530	295,510
Long-term debt	3,491,059	3,325,028	3,313,286	3,249,328	2,995,748
Total	6,191,900	5,943,170	5,799,954	5,721,389	5,462,652
First mortgage bonds maturing within one year	—	100,000	40,000	50,000	33,000
Total	$6,191,900	$6,043,170	$5,839,954	$5,771,389	$5,495,652
Capitalization ratios: *(including first mortgage bonds maturing within one year):*					
Common stock equity	36.2%	35.0%	33.5%	33.2%	34.2%
Preferred stock	7.4	8.3	9.1	9.6	10.7
Long-term debt	56.4	56.7	57.4	57.2	55.1
Financial ratios:					
Ratio of earnings to fixed charges	2.24	2.09	1.41	1.71	2.10
Ratio of earnings to fixed charges without AFC	2.17	2.03	1.35	1.66	2.06
Ratio of AFC to balance available for common stock	9.7%	9.3%	52.8%	18.3%	6.9%
Ratio of earnings to fixed charges and preferred stock dividends	1.90	1.77	1.17	1.41	1.67
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	34.1%	32.1%	36.9%	36.5%	34.6%
Other operation expenses	19.7	20.0	19.9	19.7	16.5
Maintenance, depreciation and amortization	13.5	14.4	14.4	14.4	15.1
Total taxes	17.3	16.4	14.4	15.3	16.1
Operating income	14.2	15.5	14.3	14.2	17.0
Balance available for common stock	5.9	6.0	1.3	3.6	5.7
Miscellaneous: (000's)					
Gross additions to utility plant	$ 502,244	$ 522,474	$ 431,579	$ 413,492	$ 366,142
Total utility plant	9,642,262	9,180,212	8,702,741	8,324,112	7,967,625
Accumulated depreciation and amortization	2,975,977	2,741,004	2,484,124	2,283,307	2,090,170
Total assets	8,590,535	8,241,476	7,765,406	7,562,472	7,076,041





ELECTRIC CAPABILITY

December 31,	1992	%	1991	1990
	Thousands of kilowatts			
Owned:				
Coal	1,285	15.5	1,285	1,294
Oil	1,496	18.1	1,961	1,961
Dual Fuel — Oil/Gas	700	8.5	400	400
Nuclear	1,059	12.8	1,059	1,051
Hydro	706	8.5	708	708
Natural Gas	108	1.3	164	211
	5,354	64.7	5,577	5,625
Purchased:				
New York Power Authority				
— Hydro	1,302	15.8	1,283	1,278
— Nuclear	67	.8	76	63
Non-utility generators	1,549	18.7	1,027	630
Total capability *	8,272	100.0	7,963	7,596
Electric peak load	6,205		6,093	5,792

*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.

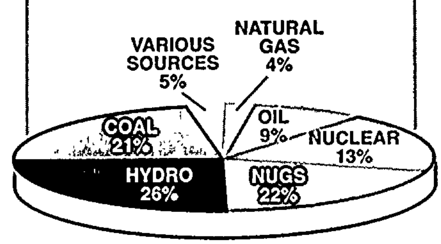
ELECTRIC STATISTICS

	1992	1991	1990
Electric sales *(Million of kw-hrs.):*			
Residential	10,392	10,321	10,310
Commercial	11,628	11,686	11,623
Industrial	11,334	11,362	11,874
Municipal service	227	228	226
Other electric systems	3,030	3,141	1,511
	36,611	36,738	35,544
Electric revenues *(Thousands of dollars):*			
Residential	$1,096,418	$ 985,347	$ 917,057
Commercial	1,160,643	1,044,725	978,684
Industrial	628,667	556,934	543,365
Municipal service	50,327	47,566	44,825
Other electric systems	93,283	106,066	69,821
Miscellaneous	118,338	166,655	115,556
	$3,147,676	$2,907,293	$2,669,308
Electric customers *(Average):*			
Residential	1,389,470	1,378,484	1,361,961
Commercial	142,345	145,098	145,231
Industrial	2,269	2,283	2,309
Other	3,262	3,231	3,158
	1,537,346	1,529,096	1,512,659
Residential *(Average):*			
Annual kw-hr. use per customer	7,479	7,487	7,570
Cost to customer per kw-hr.	10.55¢	9.55¢	8.89¢
Annual revenue per cutomer	$789.09	$714.80	$673.33

GAS STATISTICS

	1992	1991	[illegible]
Gas sales *(Thousands of dekatherms):*			
Residential	53,945	48,172	49,955
Commercial	22,289	20,226	22,823
Industrial	1,772	1,812	4,116
Other gas systems	1,190	1,519	1,723
Total sales	79,196	71,729	78,617
Transportation of customer-owned gas	65,845	50,631	34,242
Total gas delivered	145,041	122,360	112,859
Gas revenues *(Thousands of dollars):*			
Residential	$354,429	$302,900	$307,217
Commercial	132,609	113,727	128,462
Industrial	10,001	8,430	19,322
Other gas systems	4,737	6,964	7,907
Transportation of customer owned gas	42,726	36,455	22,100
Miscellaneous	9,349	6,749	403
	$553,851	$475,225	$485,411
Gas customers *(Average):*			
Residential	448,601	438,581	431,588
Commercial	39,230	37,727	37,011
Industrial	234	260	272
Other	1	2	2
Transportation	639	625	567
	488,705	477,195	469,440
Residential *(Average):*			
Annual dekatherm use per customer	120.3	109.8	115.7
Cost to customer per dekatherm	$6.57	$6.29	$6.15
Annual revenue per customer	$790.08	$690.64	$711.83
Maximum day gas sendout (dekatherms)	905,872	852,404	714,122

ELECTRICITY GENERATED AND PURCHASED 1992



Corporate Information

Annual Meeting
The annual meeting of shareholders will be held at The Desmond Hotel, 660 Albany-Shaker Road, Albany, N.Y. at 10:30 a.m., Tuesday, May 4, 1993. A notice of the meeting, proxy statement and form of proxy will be sent in early April to holders of common stock.

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

Shareholder Inquiries
Questions regarding shareholder accounts may be directed to the company's Shareholder Services Department:

(315) 428-6750
(Syracuse)

1-800-962-3236
(New York State)

1-800-448-5450
(elsewhere in continental U.S.)

Analyst Inquiries
Analyst inquiries should be directed to Leon T. Mazur, Manager-Investor Relations, (315) 428-5876.

Stock Exchange Listings
Ticker Symbol: NMK
Common stock and most preferred series are listed and traded on the New York Stock Exchange.

Bonds are traded on the New York Stock Exchange.

Disbursing Agent
Common and Preferred Stocks:
Niagara Mohawk Power Corp.
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
Common and Preferred Stocks:
Chemical Bank
450 West 33rd Street
New York, N.Y. 10001

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

Directors

[illegible] F. Allyn *(B, C, F)*
[illegible]t & Chief Executive Officer
Welch Allyn, Inc., Skaneateles Falls, NY

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

Douglas M. Costle *(A, D, F)*
Distinguished Senior Fellow,
Institute for Sustainable Communities
Vermont Law School
South Royalton, VT

Edmund M. Davis *(A, B, D, E)*
Partner, Hiscock & Barclay
Attorneys-at-Law, Syracuse, NY

William E. Davis
Vice Chairman of the Board

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

Edward W. Duffy *(A, B, F)*
Former Chairman of the Board
and Chief Executive Officer,
Marine Midland Banks, Inc.
Cooperstown, NY

John M. Endries
President

Dr. Bonnie Guiton *(A, C, D)*
De[illegible], McIntire School of Commerce
[illegible]ity of Virginia, Charlottesville, VA

[illegible]. Haehl, Jr.
Former Chairman of the Board
and Chief Executive Officer

Martha Hancock Northrup *(A, C, E)*
Homemaker, Syracuse, NY

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

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

Donald B. Riefler *(A, C, E, F)*
Financial Market Consultant
Vero Beach, FL

Stephen B. Schwartz *(B, E)*
Former IBM Senior Vice President
Palm Beach Gardens, FL

John G. Wick *(C, D, E)*
Partner, Falk & Siemer
Attorneys-at-Law, Buffalo, NY

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 Corporate Public Policy & Environmental Affairs
[illegible]mber of the Finance Committee
[illegible]ber of the Nuclear Oversight [illegible]mittee

Officers

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

William E. Davis
Vice Chairman of the Board
(Effective November 19, 1992)

John M. Endries
President

B. Ralph Sylvia
Executive Vice President, Nuclear

David J. Arrington
Senior Vice President
Human Resources

John P. Hennessey
Senior Vice President
Electric Customer Service

Gary J. Lavine
Senior Vice President
Legal & Corporate Relations
and General Counsel

Robert J. Patrylo
Senior Vice President
Gas Customer Service

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

Nicholas J. Ashooh
Vice President
Public Affairs and Corporate
Communications
(Effective August 1, 1992)

Thomas H. Baron
Vice President, Fossil Generation

Harold J. Bogan
Secretary
(Effective October 1, 1992)

Michael J. Cahill
Vice President, Regional Operations

Neil S. Carns
Vice President, Nuclear Generation
(Effective August 1, 1992)

Norman E. Crowe, Jr.
Vice President, Regional
Operations

Richard E. A. Duffy
Vice President
Public Affairs and Corporate
Communications
(Retired July 31, 1992)

Thomas R. Fair
Vice President
Environmental Affairs

Joseph F. Firlit
Vice President, Nuclear Support

Edward F. Hoffman
Vice President, Power Delivery

Darlene D. Kerr
Vice President
Gas Marketing and Rates

Samuel F. Manno
Vice President
Purchasing and Corporate Services

Douglas R. McCuen
Vice President
Government and Regulatory Relations

Clement E. Nadeau
Vice President
Power Transactions and Planning

James A. Perry
Vice President, Quality Assurance

Russell E. Perry
Vice President, Employee Relations
(Resigned June 19, 1992)

Nicholas L. Prioletti, Jr.
Vice President, Financial Planning

Arthur W. Roos
Treasurer

Richard H. Ryczek
Vice President
Gas Customer Service Operations

Jack R. Swartz
Vice President, Employee Relations
(Effective August 1, 1992)

William J. Synwoldt
Vice President, Information Systems

Steven W. Tasker
Controller

Carl D. Terry
Vice President, Nuclear Engineering

Andrew M. Vesey
Vice President, Operations Support

Stanley W. Wilczek, Jr.
Vice President, Special Projects

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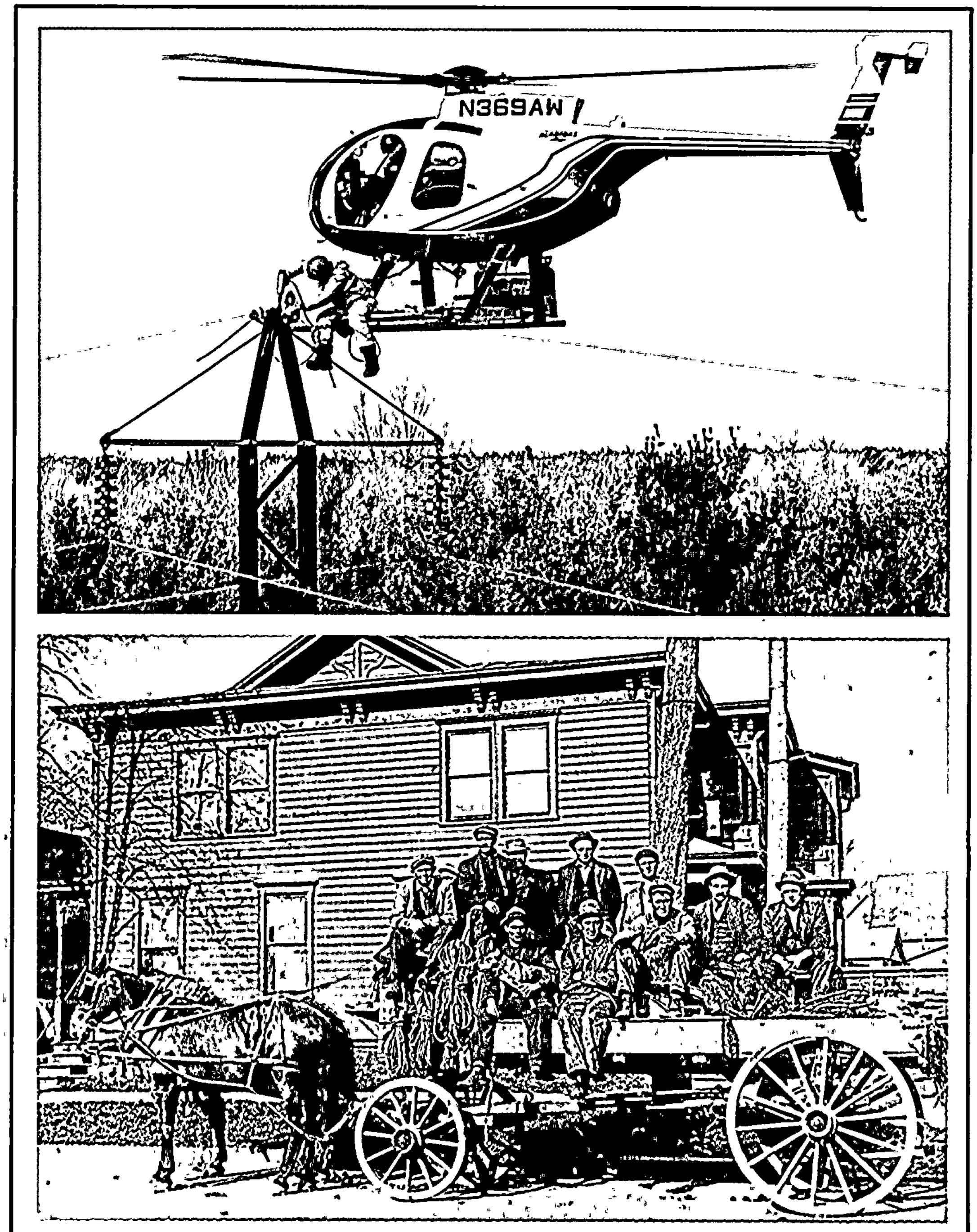

NOW ... AND THEN — Methods of maintaining transmission lines have changed since the early days, as views of a recent helicopter/platform-based replacement of a static line, top, and of a turn-of-the-century line crew, bottom, illustrate.