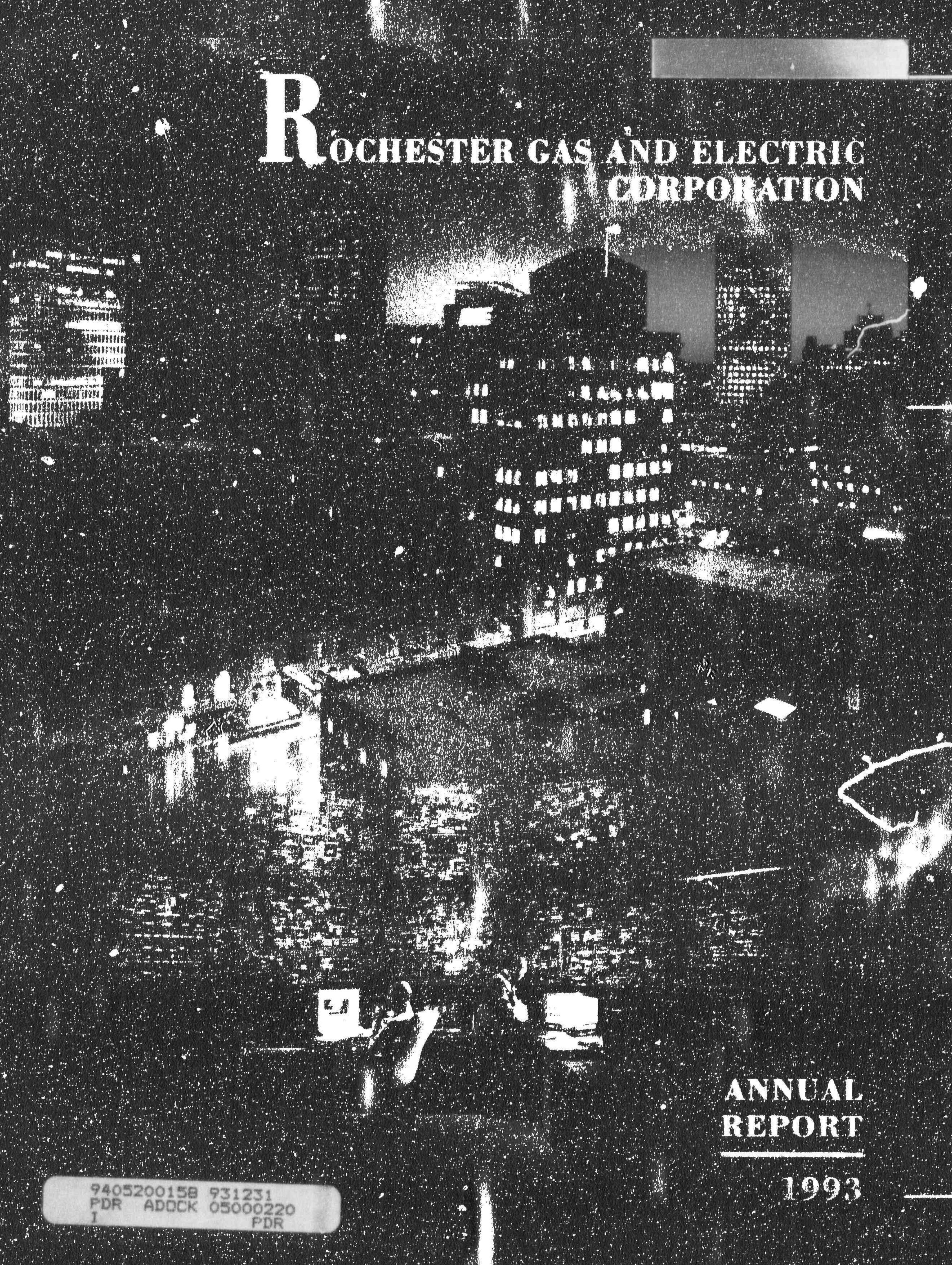
ROCHESTER GAS AND ELECTRIC CORPORATION



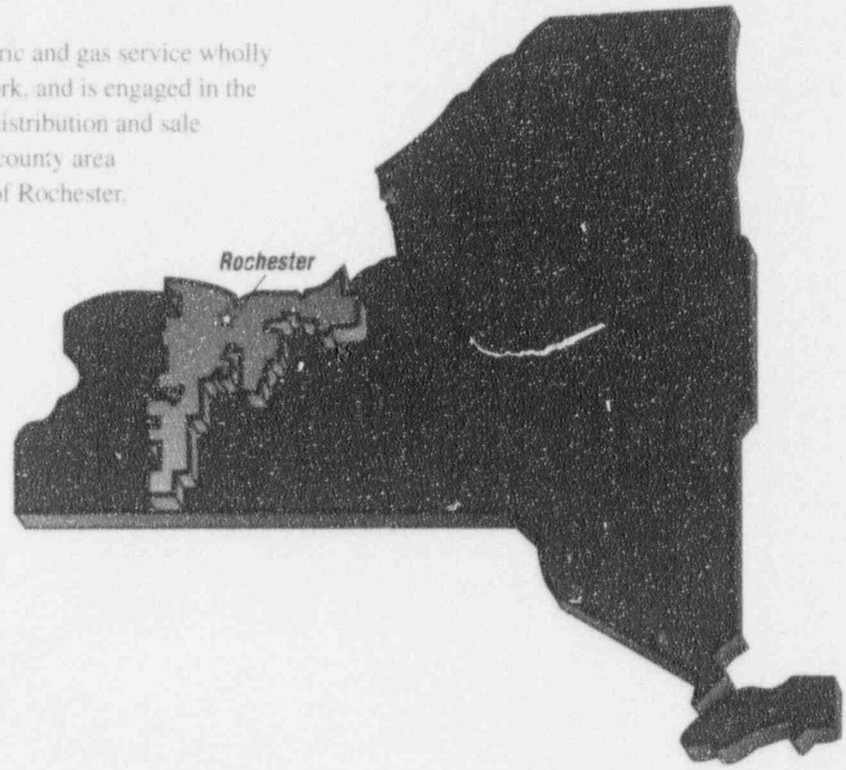
ANNUAL REPORT

1993

RG&E Service Area/Business

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

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



COVER—
Rochester's skyline highlights RG&E's new energy-efficient logo sign atop corporate headquarters. Blending with the photo at the bottom is the new Energy Control Center that monitors and controls electric and gas operations around the clock.

An RG&E Energy Control Center operator checks systems status as part of the ongoing operations at the new facility.

The RG&E lighted logo sign uses energy-efficient illumination.

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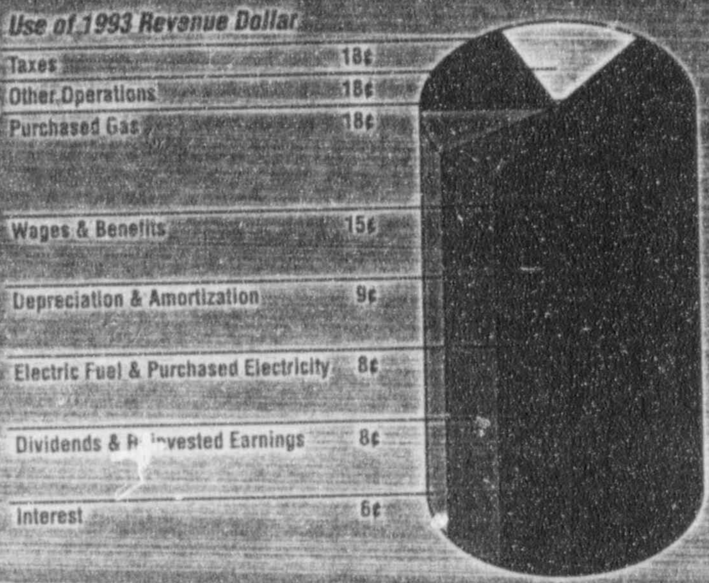
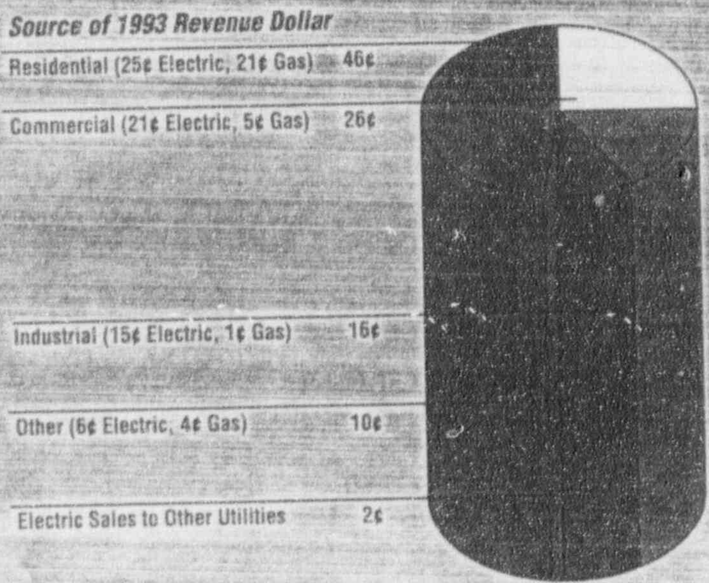
1993 Revenue Dollar





Financial Highlights

	1993	1992	% Change
Financial Data (Dollars in Thousands)			
Operating revenues: Electric	**$655,316**	$633,808	3
Gas	**$293,708**	$261,724	12
Operating expenses	**$801,791**	$761,588	5
Operating income	**$147,233**	$133,944	10
Net income	**$ 78,563**	$ 70,439	12
Earnings applicable to common stock	**$ 71,263**	$ 62,149	15
Rate of return on average common equity	**10.25%**	9.98%	3
Common Stock Data			
Weighted average number of shares outstanding (thousands)	**35,599**	33,258	7
Per common share:			
Earnings	**$2.00**	$1.86	8
Dividends	**$1.72**	$1.68	2
Book Value (year end)	**$19.70**	$18.92	4
Year-end market price	**$26.25**	$24.50	7
Number of Common Stock Shareholders at December 31	**38,102**	39,017	(2)
Operating Data			
Sales (thousands)			
Kilowatt-hours to customers	**6,507,064**	6,455,986	1
Kilowatt-hours to other utilities	**743,588**	1,062,738	(30)
Therms of gas sold and transported	**529,505**	525,387	1
Customers (year end)			
Electric	**335,874**	333,674	1
Gas	**271,353**	267,954	1
Construction expenditures, less allowance for funds used during construction (thousands)	**$139,407**	$125,207	11
Employees (year end)	**2,536**	2,702	(6)

To Shareholders


Roger W. Kober

Nineteen ninety-three was a good year for our shareholders, customers and employees alike. It's been a while since we could make a statement like that. All the indicators are favorable. Earnings were up, dividends were up, year-end common stock market price was up, sales of electricity and natural gas to customers were up, and so was favorable public opinion as measured by our annual customer attitude survey. At the same time, operation and maintenance expenses came in under forecast. The real driving force behind this improved performance is our highly motivated work force and a strong commitment to our Corporate Business Plan.

Our 1991 annual report described our business plan and its major objectives. We seek to improve customer service, make the price of our products more competitive, help ensure safety for employees and the public, maximize employee effectiveness and achieve higher degrees of public acceptance. We have recorded substantial progress in all these areas. And, as we predicted, progress in achieving these goals has improved financial performance.

Rate Settlement Agreement Milestone

In covering what I believe to be the key accomplishments of 1993, I cite our successful negotiation of a rate settlement agreement with the New York State Public Service Commission (PSC) as a prime example of our new approach in managing this Company and the competitive forces it confronts. The rate settlement agreement was a long time in the making. More than a dozen interested parties debated and negotiated components of a settlement that could work to the advantage of customers and the Company. It was a long process, but the approved agreement sets new precedents in our ratemaking procedures.

The three-year rate settlement agreement sets caps on the amount of additional revenues the Company may seek through rate relief. These caps are in the range of current inflation rates. However, the agreement provides incentives where superior performance brings rewards in shareholder earnings. Of course, penalties apply in the event our performance falls short of the negotiated goals.

Our rate settlement agreement includes a unique performance incentive. Our performance will be measured against other New York investor-owned power companies in the areas of production, electric transmission and effectiveness of demand side management programs.

We continue to move aggressively in the area of demand side management, or Energy Utilization Services as we now call it. Successful efforts to curb electric load growth through promotion of energy efficiency programs and the creation of energy

Leading The Way In Customer Service

partnerships with commercial and industrial accounts will be recognized under the settlement agreement.

We are fully committed to the rate settlement agreement and are prepared to demonstrate it as a successful ratemaking method that benefits all. It's my intention to do everything I can to avoid increases in the price of our products. I've made it clear to RG&E people that there's no such thing as an "uncontrollable cost." We should be able to find ways to exert influence on any expenses we encounter. And that includes taxes. We successfully reduced property taxes substantially at one of our power plants through an exhaustive audit of the assessments. We are finding better ways to do things. I have great expectations for the rate settlement agreement and its role in keeping us competitive.

Cost Control

The price at which we can keep our products competitive is largely a function of controlling our operating expenses. In 1993 we managed to come in $13 million under our operation and maintenance forecast. This saving was achieved by improved employee pr ductivity and ingenuity. A cost saving of $4.4 million was also br ht about through aggressive refinancing of our long-term debt.

It was the company-wide determination of RG&E people that really turned things around.

To Shareholders *cont.*

Retirement Enhancement

It was time in 1993 as a result of the new competitive environment to take action to reduce the number of employees and payroll expense. That time came for us in late 1993. Two retirement enhancement programs were offered. Of the 217 eligible employees, 173 opted for early retirement. This is not a temporary measure; it's a permanent reduction in our complement. The downsizing of the work force will improve financial performance and help us remain competitive in the years ahead. We're reshaping the corporate culture and moving the Company and its people into the mainstream of the competitive marketplace. We will remain competitive and we will remain the customers' energy supplier of choice.

Process Improvement

The system we use at RG&E to improve performance is very simple. We look at everything we do. We study the individual processes and procedures we use in our work. Then we take each process and ask ourselves how valuable it is to us and our customers. If we decide a process is not contributing to the success of our Corporate Business Plan, we get rid of it. If we see it as worthwhile, we keep it. If we can find a way to improve it, we do. And here's a key point. The "we" I refer to is not just the Executive Management Team sitting around a table making judgments. The "we" in our improvement efforts is our employees. They have been empowered and encouraged to step back, look at what we do, and then subject it to our improvement process tests. I can tell you it's working. In 1993 dozens of procedures and practices were changed at RG&E. All for the better.

Customer Service Center

Probably the most striking example of our rededication to improved customer service and satisfaction is our new Customer Service Center in Rochester. A completely renovated, 153,000-square-foot industrial complex now houses the majority of our Rochester District customer service operations under one roof. Customer contact telephone service, energy control center, computer data center, customer service departments, telecommunications, service vehicle garage and supply warehouse are now positioned in the complex to best accommodate customer needs and maintain the high level of energy reliability. Our vision had been to create a "one-stop-shopping" convenience for our customers and the highest degree of system reliability and response. Whatever the issue, our customers can now call or visit one location and get all of their needs accommodated. This new facility is a major milestone in our corporate history, and we feature it in this report.

Our strategy is consistent with our intent to break away from the old, more vulnerable utility business thinking.

Empire Pipeline

The Empire State Pipeline was completed in 1993 as scheduled. We own a share of this major natural gas transmission pipeline project that runs 156 miles from Grand Island near Buffalo to Syracuse. The 24-inch-diameter pipeline brings another source of natural gas to Upstate New York from northern fields. The pipeline is expected to supply half of our gas customers' requirements.

CO Detector

One of our corporate objectives is to maintain high levels of safety and safety awareness on the part of our employees and the public. There had been two fatalities in our area a year ago as a result of carbon monoxide poisoning. We responded by developing a safety awareness campaign that warned people of the symptoms and dangers and urged them to get their furnaces inspected annually.

RG&E People Made All The Difference

In a further effort to prevent carbon monoxide poisonings we launched an aggressive marketing campaign in October that offers industry-approved carbon monoxide detectors at our cost. They're available to customers and non-customers alike. Nearly 20,000 have been placed into operation, and we know of some 20 cases already where the detectors alerted residents to the presence of carbon monoxide.

This effort was conceived, developed and placed into action by RG&E people. Aside from its perfect fit into the corporate safety objective, I see it as another excellent example of RG&E's growth as a thinking, progressive company with talented people taking initiatives under our practice of empowerment and process improvement.

Outlook

I am very pleased with the progress we are making along the lines of the Corporate Business Plan. There's ample evidence that we have indeed turned the corner in the conduct of our business and gotten hold of our future. This is a new beginning for us, and our efforts to improve and prosper in the competitive marketplace continue with intensity.

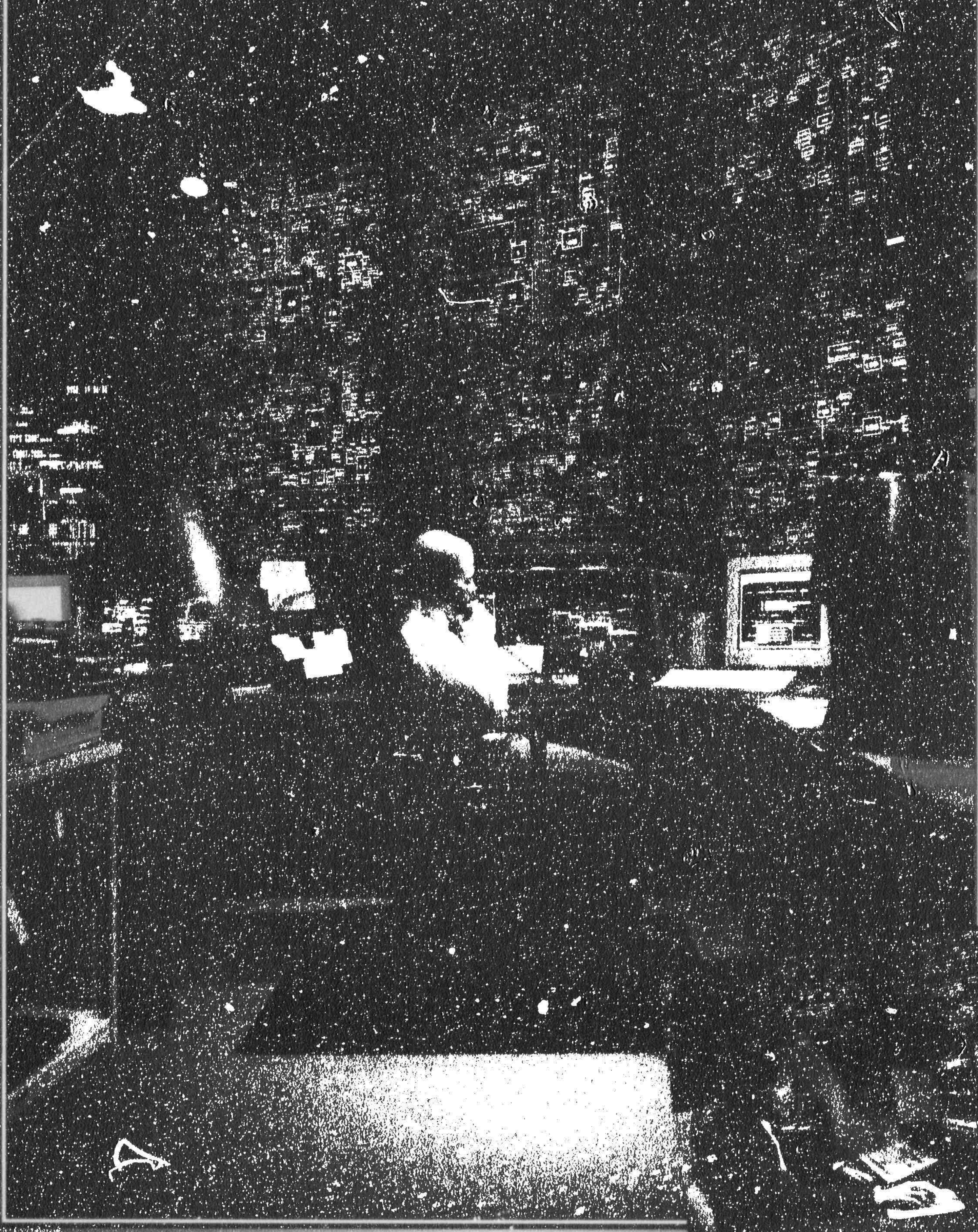
Roger W. Kober

Roger W. Kober
Chairman of the Board, President and
Chief Executive Officer
January 25, 1994

Rochester Gas and Electric Corporation

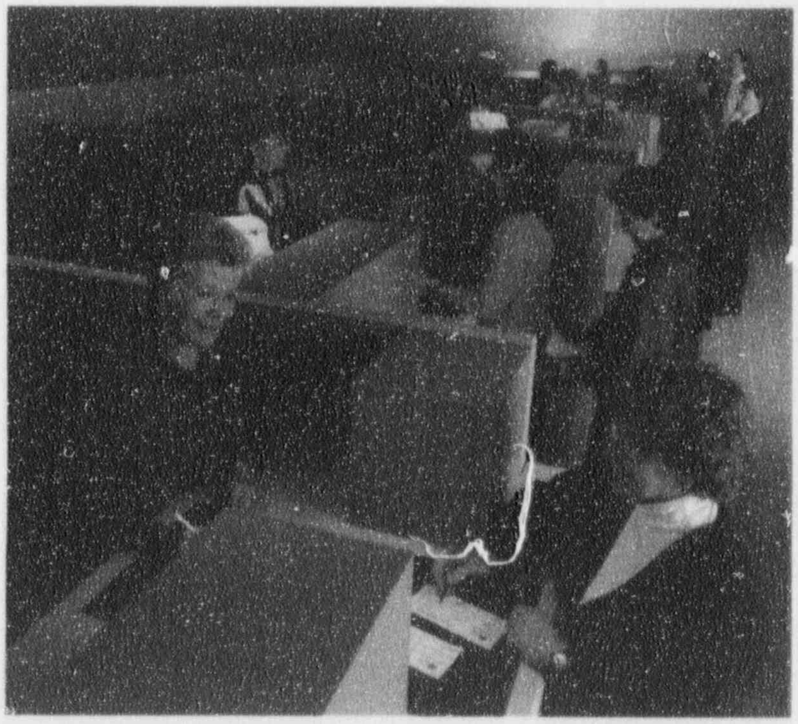
RG&E's Energy Control Center

One of a kind



Vision Becomes Reality

RG&E is looking for ways to make its dealings with customers as productive and supportive as possible and, in that process, bring about satisfactory financial results as well. These days it's hard to find any company's business plan that doesn't mention those kinds of goals. But there's a big difference between the words and the performance; between the vision and the reality.



The modern, convenient service area allows easy, "one-stop shopping" for customers.

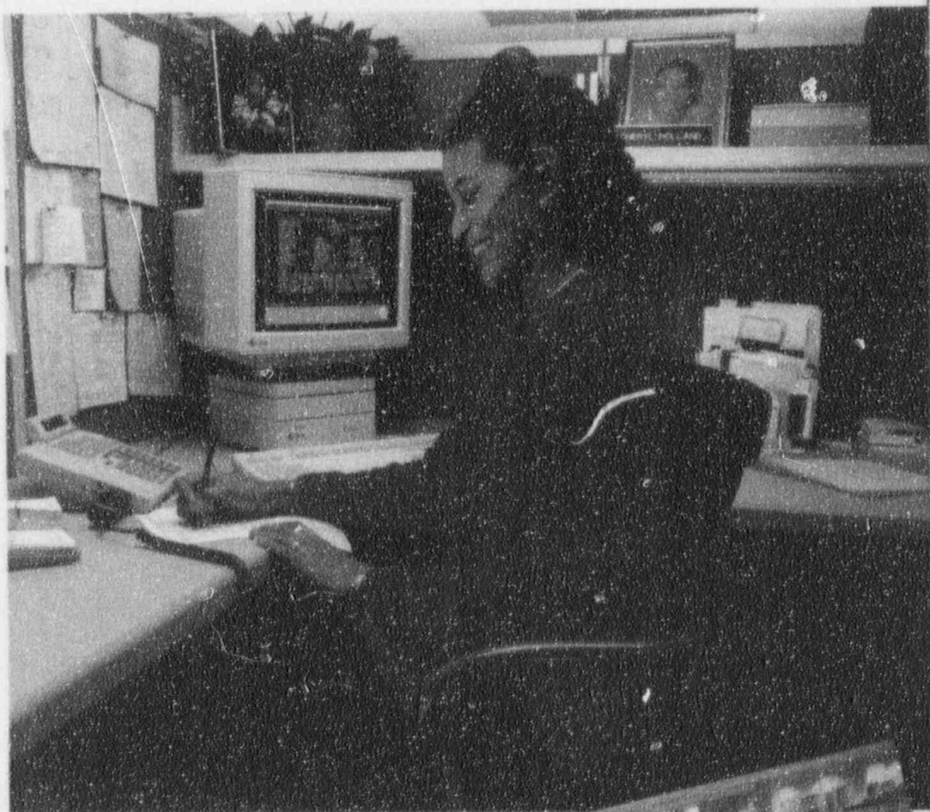
Rochester Gas and Electric Corporation brought life to a corporate vision with the opening of a new Customer Service Center in Rochester. Using advanced office design and state-of-the-art computer systems, the Center houses key components of RG&E customer account service groups along with computer, voice communications, energy control and storm emergency response operations.

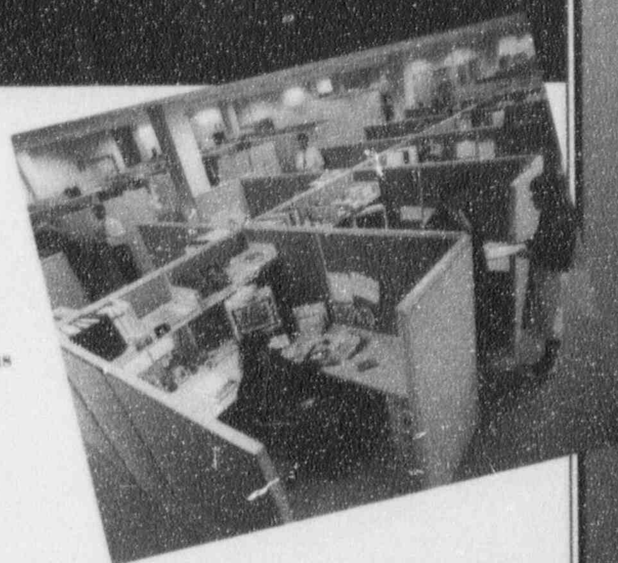
Just minutes from the heart of downtown Rochester at 400 West Avenue, the 153,000-square-foot facility took shape from a complete renovation of a vacated industrial complex. It offers a centralized location for customers visiting the center along with the convenience of easy access and ample, free parking.

Customer Satisfaction By Design

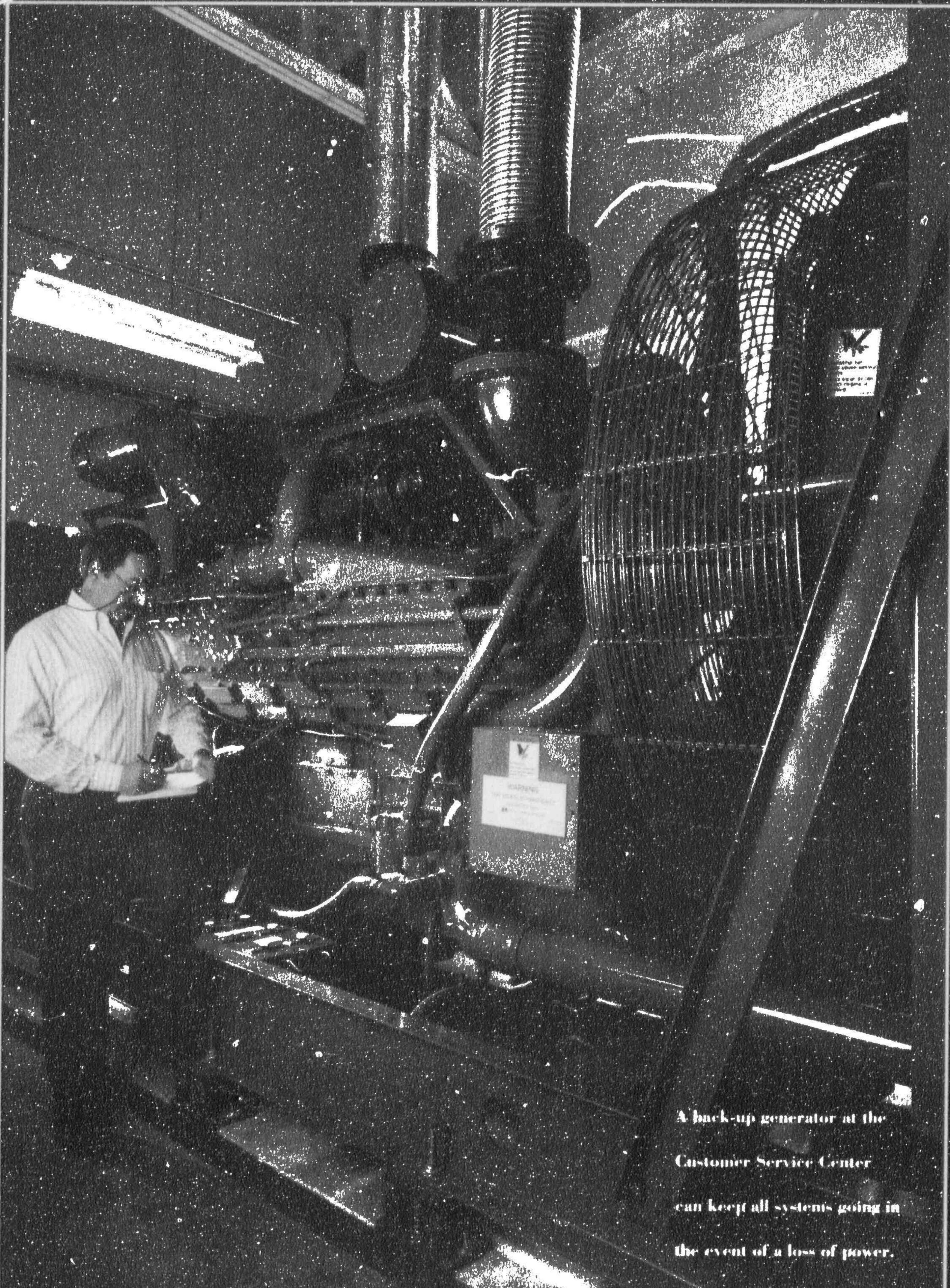
The Customer Service Center offers a spacious customer transaction area. Customer service and billing departments are located near the service area so that customer account matters can be resolved at the Center in person or over the phone from one centralized location. Conference rooms are also available for planning consultations with commercial and industrial customers.

Customer telephone representatives are well equipped to resolve account matters by phone. Advanced computer systems help experienced customer service representatives with a full range of instantly available account information. More than one million customer telephone calls a year are handled by the RG&E telephone service representatives and switchboard operators.





The Customer Telephone Service Department matches experienced representatives with state-of-the-art data systems offering "one-stop shopping" to customers by phone.



A back-up generator at the Customer Service Center can keep all systems going in the event of a loss of power.

Energy Control Center

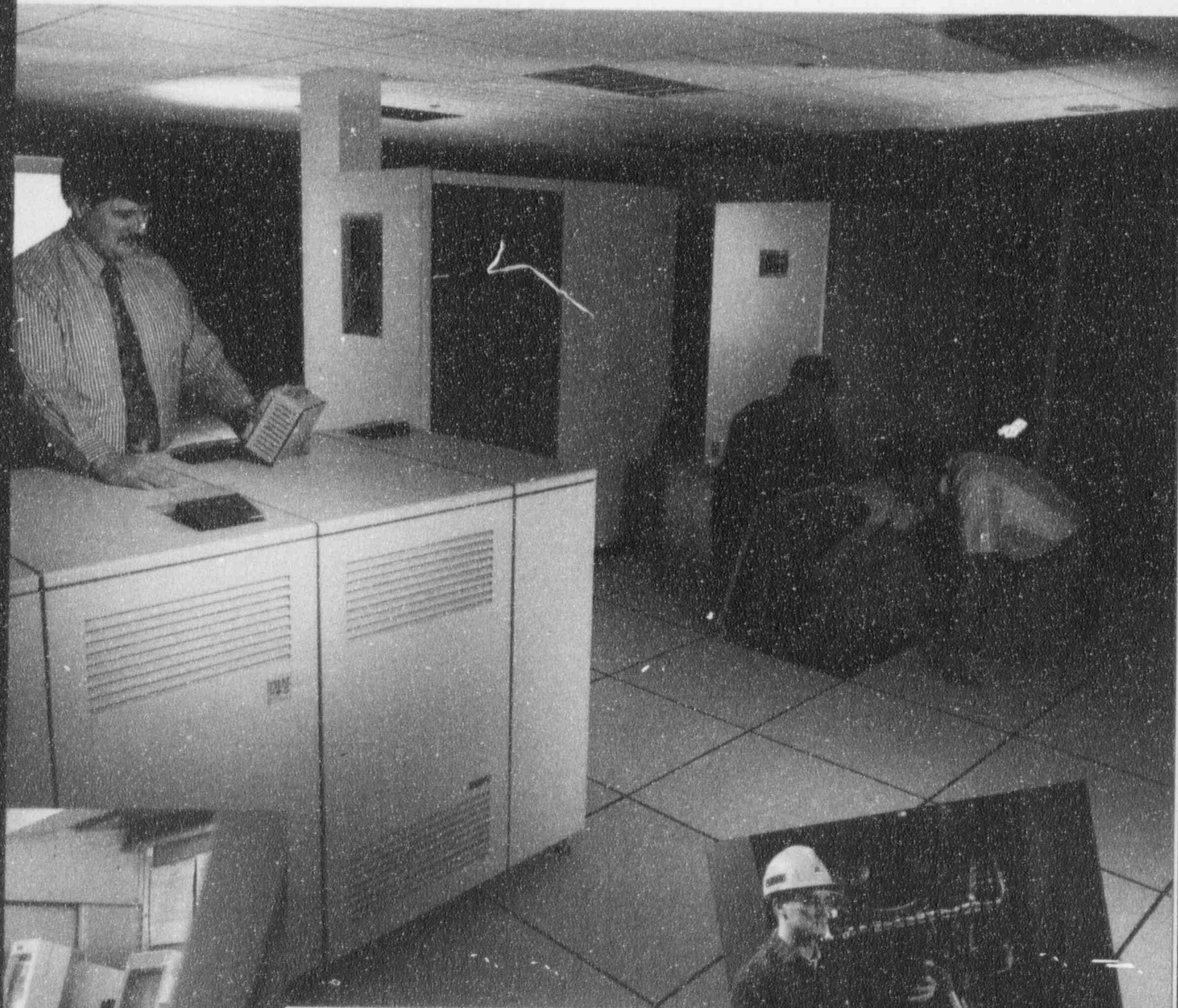
Energy reliability is crucial to good customer service. The West Avenue Customer Service Center houses a unique Energy Control Center from which electric and gas operations are orchestrated and monitored 24 hours a day. New computer systems precisely track real-time electric power and natural gas systems status. A unique array of rear-screen projections creates a valuable tool to improve routine operations and enable more effective restoration response in emergencies.

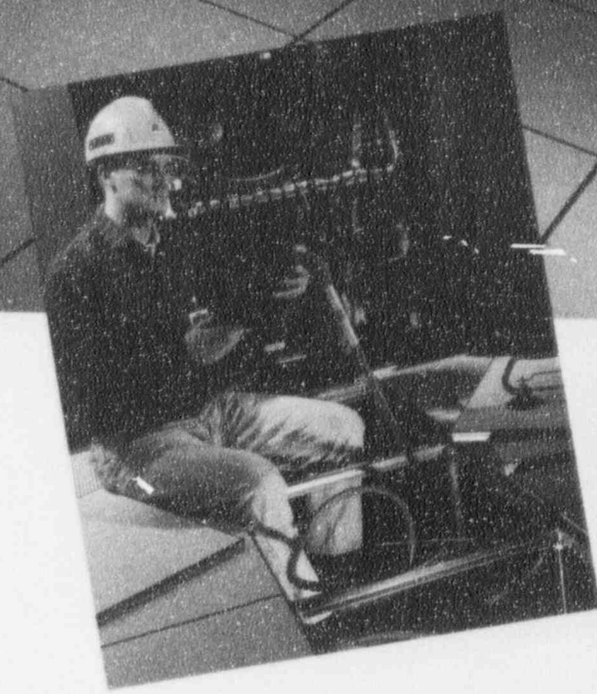
Emergency Response

Aside from its daily function as a customer service and energy control center, the Customer Service Center is specially designed to handle RG&E's emergency response activities. Restoration of electric or gas services disrupted by severe storms or other events will be directed and controlled from the Energy Control Center. The locations of the operations centers and the communication links that connect them are custom engineered to allow the most rapid and efficient energy service restorations using RG&E's emergency response plans.

Computer Data Center

Advanced computer systems are central to the accumulation and retrieval of data. The Customer Service Center is home to RG&E's main frame computers and company computer support services. Voice communications activities are also coordinated at the Center for RG&E's telecommunications systems.





The Data Center in the Customer Service Center is home to RG&E's main frame computers and computer service operations.

Truck Bay

Who would think a garage would make a big difference? Well it does at the Customer Service Center where a 22,000-square-foot truck bay comfortably houses a fleet of electric and gas service trucks and vehicles—even those with heavy construction equipment attached. With a large supply storehouse next door, equipment for jobs is quickly and easily placed aboard the trucks. They can then quickly roll out of a warm, dry garage to the job sites on cold or wet days. Besides being easier on the crews and trucks, this convenience saves time and provides more efficient response in the field.

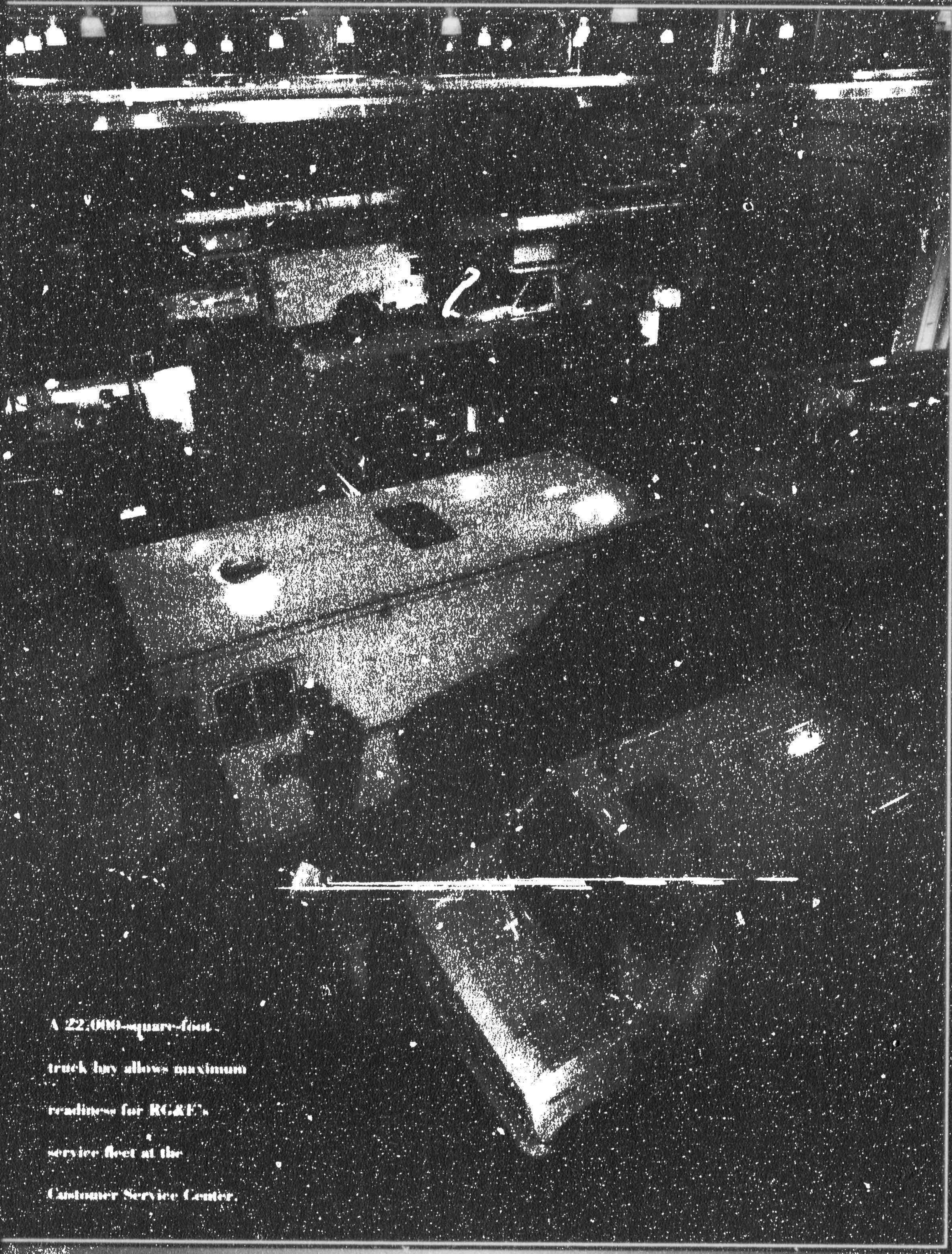
Uninterrupted Electric Power

One thing RG&E has to think about for its service facilities is what it does if it loses power itself. The RG&E Customer Service Center is equipped with redundant electric power sources and power switching units. Main frame computer operations are protected with alternative, uninterruptable power supplies. That includes a battery array that protects the equipment and data by supplying power to the main frame computers in an emergency. And, if all else fails, a 1,500-kilowatt generator inside the Customer Service Center can supply full power requirements for the whole facility indefinitely in the event all outside power is lost.

Alternative power systems help guarantee uninterrupted electric service for all systems in the Customer Service Center

A Part Of The Whole

While the West Avenue Customer Service Center is a focal point for RG&E's drive to improve customer service and energy reliability, it's not the whole story. Besides 400 employees staffing the Customer Service Center, more than 2,000 other RG&E people go about their jobs, doing their best, too, for the one million residents in the Company's 2,700-square-mile service franchise territory.



A 22,000-square-foot truck bay allows maximum readiness for RG&E's service fleet at the Customer Service Center.

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

The following is Management's assessment of significant factors which affect the Company's financial condition and operating results.

Liquidity and Capital Resources

During 1993 cash flow from operations, together with proceeds from external financing activity (see Consolidated Statement of Cash Flows), provided the funds for construction expenditures and the retirement and refinancing of long-term debt and preferred stock. Capital requirements during 1994, including debt maturity and sinking fund obligations, are anticipated to be satisfied primarily from the use of internally generated funds. Some external financing, mainly in the form of short-term debt, is expected to be incurred. Any refinancing activity would require additional external financing.

Projected Capital and Other Requirements

The Company's capital requirements relate primarily to expenditures for electric generation, transmission and distribution facilities and gas mains and services as well as the repayment of existing debt. Construction programs of the Company focus on the need to serve new customers, to provide for the replacement of obsolete or inefficient utility property and to modify facilities consistent with the most current environmental and safety regulations.

The Company has no current plans to install additional baseload generation. The Company either has contracts or is continuing negotiations for the realization of approximately 24 megawatts of capacity savings being phased-in over the 1993–1996 period under its demand side management program and, beginning in late 1994 or early 1995, expects approximately 55 megawatts of capacity to be supplied by a cogenerator under contract with the Company. The Company has no other obligations with non-utility generating companies at this time.

In June 1992 the Company filed with the New York State Public Service Commission (PSC) an Integrated Resource Plan (IRP) which is a long-range plan examining options for the future with regard to generating resources and alternative methods of meeting electric capacity requirements. The plan covers a 15-year period, beginning in 1992, and provides current strategies and alternatives for meeting customer energy requirements in a changing business and technological environment. The IRP takes into account anticipated capacity requirements and available resource options, as well as factors such as reliability, price of product, public acceptance, financial integrity, environmental issues, the competitive marketplace, demand side management and potential new technologies.

One result of the IRP was the decision made by the Company in December 1992 to replace the two steam generators at the Ginna nuclear plant in 1996. Like similar plants, the Ginna nuclear plant has experienced degradation in some of the tubes that make up each steam generator. About 30 percent of these tubes have required repair. In addition, a chemical buildup in some of the tubes has reduced their heat transfer capability. Both conditions would continue to erode the plant's performance if the existing steam generators were left in place. Installation of new steam generators was determined by the Company to be the most cost-effective, reliable and environmentally compatible option for the plant. The new steam generators should result in reduced maintenance costs and help sustain a high level of plant availability. Cost of replacement is estimated at $115 million, and preparation to replace these generators began during the plant's routine 1993 fuel outage.

As a part of the on-going IRP process, the Company in mid-1993 made a decision to place Unit 1 at Russell Station (47 MW) on cold standby, while modifying Units 2, 3 and 4 with new burners to meet Federal Environmental Protection Agency standards. Unit 1 is expected to be in cold standby by early 1994. Modification of Units 3 and 4 is expected to be completed by March 1995 at a cost of approximately $4.6 million. In addition, Unit 12 at Beebee Station and Unit 2 at Russell Station will be adjusted to produce fewer nitrogen oxides (NOx) by converting a third of the burners in each to achieve overfire air capability at a cost of approximately $1.2 million. These actions will allow the Company to comply with Phase I-Title I, NOx controls requirements of the Federal Clean Air Act, to meet projected load demands in its service territory, and to maintain a mix of fuel generation while remaining competitive and retaining wholesale sales opportunities.

Outlined below are other results of the IRP process to date:

- The plan calls for evaluating the possibility of using either alternative generation or current generating equipment in partnership with certain large industrial customers.
- The Company will continue to use demand side management programs to reduce the need for generating capacity.
- The Company will consider phasing out its coal-fired Beebee Station by the year 2000, unless it is converted to natural gas and operated under a partnership arrangement with a large customer.

The Company's capital expenditures program is under continuous review and will be revised depending upon the progress of construction projects, customer demand for energy, rate relief, government mandates and other factors. In addition to its projected construction requirements, the Company may consider, as conditions warrant, the redemption or refinancing of certain long-term securities.

Capital Requirements and Electric Operations. Electric production plant expenditures in 1993 included $42 million of expenditures made at the Company's Ginna nuclear plant, of which $15 million was incurred for preparation to replace the steam generators. In addition, nuclear fuel expenditures of $11 million were incurred at Ginna during 1993. A refueling outage at Ginna normally occurs annually for a period of approximately 40 to 50 days.

Exclusive of fuel costs, the Company's 14 percent share of electric production plant expenditures at the Nine Mile Two nuclear facility totaled $6 million in 1993. Expenditures of $5 million during 1993 were made for the Company's share of nuclear fuel at Nine Mile Two. On October 2, 1993 Nine Mile Two was taken out of service for a scheduled refueling outage. Refueling was completed and Nine Mile Two resumed full operation on December 3, 1993. The prior refueling outage occurred in 1992 from early March to early July. The next refueling outage for Nine Mile Two is anticipated to begin in May 1995.

Electric transmission and distribution expenditures, as presented in the table on page 16, totaled $29 million in 1993, of which $24 million was for the upgrading of electric distribution facilities to meet the energy requirements of new and existing customers.

Capital Requirements and Gas Operations. Construction began in June 1993 on the Empire State Pipeline (Empire), an intrastate natural gas pipeline subject to PSC regulation between Grand Island and Syracuse, New York. The Company received its first gas deliveries through the pipeline in early November 1993. This pipeline will provide capacity for up to 50 percent of the Company's gas requirements by its second year of operation. The Company is participating as an equity owner of Empire, along with subsidiaries of Coastal Corporation and Westcoast Energy Inc. In June 1991 the PSC authorized the Company to invest up to $20 million in Empire subject to certain conditions, notably that the investment not be included in rate base. In 1992 the Company formed a wholly owned subsidiary, Energyline Corporation, to acquire its ownership interest in Empire. The Company's share of ownership in Empire will be dependent upon final project costs and the timing and method of financing selected by the Company. In June 1993 Empire secured a $150 million credit agreement, the proceeds of which are to finance approximately 75 percent of the total construction cost. At December 31, 1993 the Company had invested a net amount of $10.2 million in Energyline ($9.9 million in 1992 and $0.3 million in 1993) and was committed for $9.7 million of the borrowings under the credit agreement. In December 1993 the Company's investment in Energyline was consolidated for accounting and reporting purposes into the accounts of the Company. Such consolidation resulted in a $0.5 million charge to Other Income during 1993.

In addition to the Empire project discussed above, construction expenditures in the Gas Department totaled $20 million and were principally for the replacement of older cast iron mains with longer-lasting and less expensive plastic and coated steel pipe, the relocation of gas mains for highway improvement, and the installation of gas services for new load.

Environmental Issues

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. In recognition of the Company's responsibility to preserve the quality of the air, water, and land it shares with the community it serves, the Company has taken a variety of measures (e.g., self-auditing, recycling and waste

Capital Requirements

	Actual			Projected		
	1991	1992	1993 (Millions of Dollars)	1994	1995	1996
Type of Facilities						
Electric Property:						
Production	$ 44	$ 47	$ 54	$ 55	$ 66	$ 76
Transmission and Distribution	29	35	29	26	36	40
Street Lighting and Other	2	2	2	1	2	2
Subtotal	75	84	85	82	104	118
Nuclear Fuel	12	11	16	20	20	22
Total Electric	87	95	101	102	124	140
Gas Property	22	19	20	19	28	25
Common Property	13	15	21	15	16	16
Total	122	129	142	136	168	181
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	4	2	2	2	3	3
Deferred Financing Charges Included in Other Income	5	3	1	-	-	-
Total Construction Requirements	131	134	145	138	171	184
Securities Redemptions, Maturities and Sinking Fund Obligations*	92	160	212	39	3	21
Total Capital Requirements	$223	$294	$357	$177	$174	$205

*Excludes prospective refinancings.

minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations and, specifically, to manage and appropriately dispose of wastes currently being generated. The Company, nevertheless, has been contacted, along with numerous others, concerning wastes shipped off-site to licensed treatment, storage and disposal sites where authorities have later questioned the handling of such wastes. In such instances, the Company typically seeks to cooperate with those authorities and with other site users to develop cleanup programs and to fairly allocate the associated costs.

As a part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and Remediation (SIR) efforts at Company-owned sites where past waste handling and disposal may have occurred. The Company currently estimates the total costs it could incur for SIR activities at Company-owned sites to be about $20 million. This estimate will vary as better site information is available. The Company anticipates spending $10 million over the next 5 years on SIR initiatives. Approximately $4.5 million has been provided for in rates through June 1996 for recovery of SIR costs. To the extent actual expenditures differ from this amount, they will be deferred for future disposition and recovery as authorized by the PSC. Additional environmental issues are discussed in Note 10 of the Notes to Financial Statements.

The Company is developing strategies responsive to the Federal Clean Air Act Amendments of 1990 (Amendments). The Amendments primarily affect air emissions from the Company's fossil-fueled electric generating facilities (see Note 10 of the Notes to Financial Statements). The Company is in the process of identifying the optimum mix of control measures that will allow the fossil fuel based portion of the generation system to fully comply with applicable regulatory requirements. Although work is continuing, not all compliance control measures have been determined. The Company has adopted control measures for NOx emissions which must be in effect by the federally mandated compliance date of May 31, 1995. These control measures are discussed under Projected Capital and Other Requirements. Capital costs for NOx controls and the installation of continuous emission monitoring systems are not expected to exceed $6.8 million and will be incurred during 1994 and 1995. A range of capital costs between $20 million and $30 million (1993 dollars) has been estimated for the implementation of several potential scenarios which would enable the Company to meet the foreseeable future NOx and sulphur dioxide requirements of the Amendments. These capital costs would be incurred between 1996 and 2000. The Company currently estimates that it could also incur up to $2 million (1993 dollars) of additional annual operating expenses, excluding fuel, to comply with the Amendments. The use of scrubbing equipment is not presently being considered. Likewise, the purchase or sale of "emission allowances", as allowed by the Amendments, is not currently being considered. The Company anticipates that the costs incurred to comply with the Amendments will be recoverable through rates based on previous rate recovery of environmental costs required by governmental authorities.

Competition

The Company is operating in an increasingly competitive environment. In its electric business, this environment includes a federal trend toward deregulation and a state trend toward incentive regulation. In addition, excess capacity in the region, new technology and cost pressures on major customers have created incentives for major customers to investigate different electric supply options. Initially, those options will include various forms of self generation, but may eventually include customer access to the transmission system in order to purchase electricity from suppliers other than the Company. As discussed under the Regulatory Matters section, the passage of the National Energy Policy Act of 1992 has accelerated these competitive challenges.

The Company accepts these challenges and is working to anticipate the impact of the increased competition. Its Business Plan, both in detail for one year and in summary for five years, focuses on improving service while reducing expenses. The Company is engaged in a continuous process improvement program to find opportunities for improved service and efficiency and has implemented an early retirement program in which 173 people, representing approximately seven percent of its workforce, have retired early and will not be replaced. In addition, the Company has agreed to a three-year rate settlement which includes caps on rate increases that approximate or are less than projected inflation, contains incentive programs that tie performance to earnings and stabilizes revenue through revenue adjustment mechanisms. An agreement has been reached with the PSC Staff and others on the terms of a competitive rate tariff that would allow negotiated rates with larger industrial and commercial customers that have competitive electric supply options. These regulatory changes are discussed in more detail in the Regulatory Matters section.

Competition in the Company's gas business has existed for some time, as the larger customers have had the option of obtaining their own gas supply and transporting it through the Company's distribution system. This process has been accelerated with FERC Order 636, discussed in more detail in the Regulatory Matters section. In addition to the matters discussed above, the Company has responded to the changes in the gas business by positioning itself to obtain greater access to both U.S. and Canadian natural gas supplies and storage, so that it can take advantage of the unbundling of services that results from FERC Order 636. A major element of this strategy went into place in 1993 with the start-up of the Empire State Pipeline. The Company is engaged in various aspects of capacity release and is investigating other options available to it to mitigate its cost and increase its revenue in the new gas regulatory environment.

Beyond the Company's efforts to remain competitive in its core business, it is conducting a broad review of its general business strategy to identify opportunities that will exist in this changed environment. This may result in expansion of various elements of the core business or engaging in new, but related, business activity.

Redemption of Securities

Discretionary first mortgage bond redemptions totaled $120 million during 1993. A $75 million first mortgage bond maturity and $17 million of sinking fund obligations were also a part of the Company's capital requirements in 1993.

Capital requirements in 1992 included a $75 million first mortgage bond maturity, and discretionary first mortgage bond redemptions of $79.5 million.

Capital Requirements—Summary

The Company's capital program is designed to maintain reliable and safe electric and natural gas service, to improve the Company's competitive position, and to meet future customer service requirements. Capital requirements for the three-year period 1991 to 1993 and the current estimate of capital requirements through 1996 are summarized in the table on page 16.

For the period 1994 through 1996, the Company anticipates construction requirements to total approximately $493 million. Replacement of the steam generators at the Ginna nuclear plant is scheduled to be completed in 1996. Electric production plant expenditures over the period include $16 million in 1994, $29 million in 1995, and $50 million in 1996 for that replacement. In addition to its construction expenditures, the Company has security maturities and sinking fund obligations totaling $63 million over the three-year period 1994 through 1996. Excluded from the capital requirements table on page 16 are expenditures associated with the Company's obligations to the United States Department of Energy for nuclear waste disposal and the Department of Energy's uranium enrichment facility decommissioning (see Notes 1 and 10 of the Notes to Financial Statements).

Financing and Capital Structure

Capital requirements in 1993 were satisfied by a combination of long-term debt and equity issues, internally generated funds, and short-term borrowings. Common shareholders equity increased during 1993 as the result of a public issue of one and one-half million shares of Common Stock in September. Favorable market conditions allowed the Company to refinance $120 million of its higher-cost long-term debt in 1993. In addition, the Company was able to refinance at a lower interest rate $75 million of its First Mortgage, 8.60% Bonds, Series LL, which matured on August 1. Such refinancing activity over the past three years has helped to reduce the annual cost of long-term debt by approximately $8.8 million and contributed to a drop in the Company's embedded cost of long-term debt from 8.6% at year-end 1990 to 7.4% at the end of 1993.

The Company believes that an average of approximately 85 percent to 90 percent of the funds required per year for its 1994 through 1996 construction program will be generated internally and the balance will be obtained through the issue of securities and short-term borrowings. The Company is utilizing its credit agreements to meet any interim external financing needs prior to issuing any long-term securities. As financial market conditions warrant, the Company may, from time to time, issue securities to permit the early redemption of higher-cost senior securities. The Company's financing program is under continuous review and may be revised depending upon the level of construction, financial market conditions, rate relief, cost of capital and other factors.

Financing. Interim financing is available from certain domestic banks in the form of short-term borrowings under a $90 million revolving credit agreement which continues until December 31, 1996 and may be extended annually. Borrowings under this agreement are secured by a subordinate mortgage on substantially all of the Company's property except cash and accounts receivable. In addition, the Company entered into a Loan and Security Agreement with a domestic bank until December 31, 1994 providing for up to $20 million of short-term debt. Borrowings under this agreement, which can be renewed annually, are secured by the Company's accounts receivable. The Company also has unsecured short-term credit facilities totaling $70 million. At December 31, 1993 the Company had short-term borrowings outstanding of $68.1 million, consisting of $51.3 million of unsecured short-term debt and $16.8 million of secured short-term debt.

Under provisions of the Company's Certificate of Incorporation (Charter), the Company may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of the Company's total secured indebtedness, capital, and surplus without the approval of at least a majority of the holders of outstanding Preferred Stock. Under this restriction, the Company as of December 31, 1993 was able to issue $19.2 million of additional unsecured debt. Additional interim financing capability remains available with secured borrowings under the Company's credit agreements, as discussed above.

During 1993 the Company sold several issues of First Mortgage Bonds, Designated Secured Medium-Term Notes, Series A aggregating $200 million principal amount. Proceeds from the sale of the medium-term notes were used to redeem prior to maturity, at lower interest rates, $120 million principal amount of first mortgage bonds, to pay at maturity $75 million principal amount of first mortgage bonds and to repay short-term debt of $5 million.

In July 1993 the Company filed a shelf registration on Form S-3 providing for the offering of $250 million of new securities. The Company may use the shelf registration to offer, from time to time, its first mortgage bonds in one or more series, its Preferred Stock in one or more series and/or its Common Stock depending on market conditions and Company requirements. This

Registration Statement became effective August 1993 and allows the Company financing flexibility regarding the timing of new issues. The net proceeds from the sale of the securities will be used to finance a portion of the Company's capital requirements, to discharge or refund certain outstanding indebtedness or preferred stock of the Company, to satisfy certain sinking fund obligations, or for general corporate purposes.

In September 1993 the Company sold 1,500,000 shares of new Common Stock in a public offering under the shelf registration discussed above. The offering raised $43.1 million in net proceeds, which were used to retire short-term debt incurred in the Company's construction program.

During 1993 approximately 515,000 new shares of Common Stock were sold through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan), providing approximately $14.1 million to help finance its capital expenditures program. New shares issued in 1992 and 1993 through the ADR Plan were purchased from the Company at a market price above the book value per share at the time of purchase.

Capital Structure. The public sale of Common Stock in 1992 and 1993 strengthened the Company's common equity. The Company's retained earnings at December 31, 1993 were $75.1 million, an increase of approximately $8.1 million compared with a year earlier. Common equity (including retained earnings) comprised 44.0 percent of the Company's capitalization at December 31, 1993, with the balance being comprised of 6.6 percent preferred equity and 49.4 percent long-term debt. At December 31, 1993 the Company had $21.3 million of long-term debt due within one year and $6.0 million of preferred stock redeemable within one year which, if included in capitalization, would increase the long-term debt component of capitalization at 1993 year-end to 49.8 percent, raise the preferred equity to 6.9 percent and reduce common equity to 43.3 percent of capitalization. As presented, these percentages are based on the Company's capitalization inclusive of its long-term liability to the United States Department of Energy (DOE) for nuclear waste disposal as explained in Note 1 of the Notes to Financial Statements. It is the Company's long-term objective to move to a less leveraged capital structure and to increase the common equity percentage of capitalization toward the 45 percent range. To improve its capital structure, the Company anticipates the issuance of new shares of common stock, primarily through the Company's ADR Plan, and will consider the redemption of higher-cost senior securities.

Regulatory Matters

New York State Public Service Commission (PSC). The Company is subject to regulation of rates, service, and sale of securities, among other matters, by the PSC. On August 24, 1993 the PSC issued an order approving a settlement agreement (1993 Rate Agreement) among the Company, PSC Staff and other interested parties. This agreement resolves the Company's rate case proceedings initiated in July 1992. Retroactive application of new rates to July 1, 1993 was authorized by the PSC. The 1993 Rate Agreement will determine the Company's rates through June 30, 1996 and includes certain incentive arrangements providing for both rewards and penalties. A summary of recent PSC rate decisions is presented in the table on page 22. The 1993 Rate Agreement amounts are based on an allowed return on common equity of 11.50% through June 30, 1996. Earnings between 8.50% and 14.50% will be absorbed/retained by the Company. Earnings above 14.50% will be refunded to the customers. If, but not unless, earnings fall below 8.50%, or cash interest coverage falls below 2.2 times, the Company can seek relief by petitioning the PSC for a review of the 1993 Rate Agreement terms.

The following measures were incorporated into the 1993 Rate Agreement:

- Incentive mechanisms that have the potential to either increase or reduce earnings from 5 to 70 basis points each, depending on the Company's ability to meet a variety of prescribed targets in the areas of electric fuel costs, demand side management, service quality, and integrated resource management (relative electric production efficiency). During the rate year ending June 30, 1994, these incentives have the potential to affect earnings by approximately $12 million.
- Mechanisms for sharing costs between customers and shareholders for operation and maintenance expenses. In general, non-fuel operation and maintenance expense variations are treated in three different ways depending upon the amount of control the Company can exert over them. Those costs that are directly manageable (approximately $172 million in the first rate year) have no sharing and are absorbed by the Company, those costs that are not significantly affected by management action in the short run (approximately $34 million in the first rate year) are trued up 100% and variances resulting from all other such costs (approximately $110 million in the first rate year) are shared 50% by customers and 50% by the Company.
- Mechanisms for sharing 50% of overspending variances between forecasted and actual electric capital expenditures related to production and transmission facilities. The Company will retain the savings for cost of money and depreciation on underspending variances. The settlement also provides for a sharing mechanism regarding the replacement of the Ginna nuclear station steam generators. A graduated sharing percentage is applied for up to $15 million of variances, plus or minus, from the forecasted cost of $115 million. Variances above $130 million or below $100 million are absorbed by the Company.
- An Electric Revenue Adjustment Mechanism (ERAM) designed to stabilize electric revenues by eliminating the impact of variations in electric sales. A gas weather normalization clause previously in place was retained.

To the extent incentive and sharing mechanisms apply, the negotiated rate increases shown in the table on page 22 may be adjusted up or down in the second and third year of the agreement. Negotiated electric rate increases could be reduced to zero or increased up to an additional 1.5% in year two, 1.6% in year three and 1.8% in the subsequent year. Negotiated gas rate increases could also be reduced to zero or increased up to an additional 0.8% in year two, 0.9% in year three, and 1.1% in the subsequent year, exclusive of the impact of the Empire State Pipeline going into service.

In July 1993 the Company requested approval from the PSC for a new flexible pricing tariff for major industrial and commercial electric customers. A settlement in this matter was filed with the PSC on November 19, 1993 and a decision on whether or not to approve the settlement is expected early in 1994. Such a tariff would allow the Company to negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Under the terms of the settlement, the Company would absorb 30 percent of any net revenues lost as a result of such discounts through June 1996, while the remainder would be recovered from other customers. The portion recoverable after June 1996 is expected to be determined in a generic proceeding currently being conducted by the PSC.

In September 1993 the PSC instituted a formal proceeding to investigate what the Company believes are undercharges to gas customers for certain gas purchases for the period August 1990 to August 1992. The Company's estimate of these undercharges is approximately $7.5 million, of which $2.3 million had been previously expensed and $5.2 million had been deferred on the Company's balance sheet. The PSC has made the Company's current gas rates under the 1993 Rate Agreement temporary solely to consider the impact of these under-

Rate Increases

Granted

Class of Service	Effective Date of Increase	Amount of Increase (Annual Basis) (000's)	Percent Increase	Authorized Rate of Return on Rate Base	Authorized Rate of Return on Equity
Electric	July 12, 1990	$36,059	6.6%	9.91%	12.10%
	July 1, 1991	33,133	5.5	9.66	11.70
	July 1, 1992	32,220	5.2	9.31	11.00
	July 1, 1993*	18,500	2.8	9.46	11.50
	July 1, 1994*	20,900	2.9	9.39	11.50
	July 1, 1995*	21,800	2.9	9.41	11.50
Gas	July 12, 1990	4,250	1.7	9.91	12.10
	July 1, 1991	1,148	0.4	9.66	11.70
	July 1, 1992	12,316	4.1	9.31	11.00
	July 1, 1993*	2,600	1.1	9.46	11.50
	July 1, 1994*	4,400	1.8	9.39	11.50
	July 1, 1995*	4,300	1.7	9.41	11.50

*See under heading Regulatory Matters for additional details.

charges. On December 30, 1993, a proposed settlement among the Company, PSC Staff and another party was filed with the PSC. It provides for the recovery in rates of $3.2 million over three years, subject to audit and to limitations on rate adjustments established in the August 24 Order. The Company wrote off the $2.0 million balance of the undercharges as of December 31, 1993. That write-off amounts to a reduction in 1993 earnings of approximately $.04 per share, net of tax. Although no party, to the Company's knowledge, opposes the proposed settlement the Company is unable to predict whether the PSC will approve it. A PSC decision on whether to approve this settlement is not expected before March 1994.

In its June 1992 rate decision, the PSC allowed the Company to defer and recover through rates over a period of ten years approximately $21.3 million of non-capital incremental storm-damage repair costs which the Company had incurred as a result of a March 1991 ice storm. The PSC has permitted the unamortized balance of these allowed costs to be included in rate base. Rate recovery of an additional $8.2 million of non-capital storm-damage costs incurred by the Company was denied by the PSC and the Company accordingly recorded in the second quarter of 1992 a charge to earnings in the amount of $8.2 million, equivalent to approximately $.15 per share, net of tax, after issuance of the two million shares of stock in August 1992.

Pursuant to a November 1991 Order approving a settlement agreement between the PSC Staff and the Company relating to the Staff's audit of the Company's fuel procurement practices, the Company refunded $10 million to its electric customers through adjustments to their energy bills over a twelve-month period beginning in January 1992. The Company recorded a $6.6 million net-of-tax reduction to net income, thereby reducing earnings per share by approximately $.21 for the fourth quarter of 1991.

National Energy Policy Act of 1992. The National Energy Policy Act (Energy Act) was signed into law in 1992. Major provisions of the Energy Act, as they relate to the Company, include energy efficiency, promoting competition in the electric power industry at the wholesale level, streamlining of federal licensing of nuclear power plants, encouraging development and production of coal resources, and ensuring that a new class of independent power producers established under the bill, as well as qualified facilities and other electric utilities, can achieve access to utility-owned transmission facilities upon payment of appropriate prices.

Under the Energy Act, FERC may order utilities to provide wholesale transmission services for others only if, among other things, the order meets certain requirements as to cost recovery and fairness of rates. FERC is prohibited, however, from ordering retail wheeling, i.e. transmitting power directly to a customer from a supplier other than the customer's local utility. The law, however, does not prevent state regulatory commissions from allowing or ordering intrastate retail wheeling; and, New York State is currently considering the issue of retail wheeling through various studies and hearings. The Company believes this Act could lead to enhanced competition among the Company and other service providers in the electric industry.

FERC Order 636. In April 1992 FERC issued Order No. 636 with the intention of fostering competition and improving access of customers to gas supply sources. In essence, FERC Order No. 636 requires interstate natural gas companies to offer customers "unbundled", or separate, sales and transportation services. FERC Order 636 enables the Company and other gas utilities to contract directly with gas producers for supplies of natural gas. With the unbundling of services, primary responsibility for reliable natural gas supply has shifted from interstate pipeline companies to local distribution companies, such as the Company. Since 1988 the Company has endeavored to diversify both its natural gas supply sources and the pipelines on which that supply is delivered to the Company's distribution system. The unbundling of services as required under FERC Order 636 and the commencement of Empire State Pipeline operation have enabled the Company to achieve those goals, which should enhance its competitive position. As a result of FERC Order 636, the Company does face certain restructuring transition costs as explained under the heading Energy Costs and Supply—Gas.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1993 to 1992 and 1992 to 1991. The Notes to Financial Statements on pages 36 to 53 of this report contain additional information.

Operating Revenues and Sales

Compared with a year earlier, operating revenues rose six percent in 1993 following a five percent increase in 1992. Gains in retail customer electric and gas revenues offset a decline in electric revenues from the sale of electric energy to other utilities. Customer revenue increases in 1993 resulted primarily from rate relief and the impact of warmer weather on air conditioning usage. Details of the revenue changes are presented in the table on page 24. As presented in this table, the base cost of fuel has been excluded from customer consumption and is included under fuel costs, revenue taxes are included as a part of other revenues, and unbilled revenues are included in each caption as appropriate.

Unbilled revenues are the estimated revenues attributable to energy which has been delivered to customers but for which the metered amount has not been read and recorded on the Company's books. Such revenues do not enhance the Company's cash position. The Company records monthly accruals for unbilled revenues. The Company's Statement of Income reflects net unbilled revenues of $18.7 million in 1993, $(0.8) million in 1992, and $2.6 million in 1991. Primarily as a result of the seasonal nature of gas revenues, unbilled revenues can fluctuate from month to month and will normally be near their maximum around January and at their minimum near the end of June.

Under the ERAM provisions of the 1993 Rate Agreement, as discussed under Regulatory Matters, the Company is comparing, on a monthly basis, actual results to forecast electric gross margins as defined (basically, revenues less incremental cost of fuel) and utilized in establishing rates. Variations between these target margins and the Company's actual margins may be deferred and either recovered from or returned to customers. As discussed earlier, the 1993 Rate Agreement "caps", that is limits, the amount of revenue increases that can be obtained each rate year. At the end of each rate year (i.e. June 30) any balance for ERAM will be taken into consideration along with other balances eligible for passback or surcharge to customers (primarily incentive and expense sharing provisions) to determine the final disposition of the balance. As of December 31, 1993 no provisions to accrue or defer revenues associated with any of the ERAM incentive or sharing provisions under the 1993 Rate Agreement had been made, except for fuel adjustment clause revenues.

Changes in fuel and purchased power cost revenues are normally earnings neutral. The Company, however, does have fuel clause provisions which currently provide that customers and shareholders will share, generally on a 50%/50% basis subject to certain incentive limits, the benefits and detriments realized from actual electric fuel costs, generation mix, sales of gas to dual-fuel customers and sales of electricity to other utilities compared with PSC-approved forecast, or base rate, amounts. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were increased by $4.4 million in 1992 and in 1993, primarily reflecting actual experience in both electric fuel costs and generation mix compared with rate assumptions. Fuel clause revenues also include the recovery of incremental margins that vary from those provided for in base rates for the implementation of the Company's energy efficiency programs (discussed below in this section). Beginning in October 1993, the Company also began the recovery through its fuel adjustment clause of deferred costs associated with the DOE's assessment for future uranium enrichment decontamination. For the 1992 comparison period, fuel clause revenues were reduced due to a refund to electric customers resulting from a PSC fuel audit settlement as described in the last paragraph under the heading New York State Public Service Commission.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from space heating customers comprise about 85 to 90 percent of total gas operating revenues. Variation in weather conditions can also have a meaningful impact on the volume of gas delivered and the revenues derived from the transportation of customer-owned gas since a substantial portion of these gas deliveries is ultimately used for space heating. After experiencing unseasonably mild weather during the 1991 heating season, weather in the Company's service area during 1992 and 1993 was colder than normal. Gas sales were enhanced as a result of this cooler weather, while unseasonably warm summer weather during 1993 boosted electric energy sales to meet the demand for air conditioning usage, compared with the cool, wet 1992 summer weather conditions. The decoupling, or

Operating Revenues

Increase or (Decrease) from Prior Year

	Electric Department		Gas Department	
(Thousands of Dollars)	**1993**	1992	**1993**	1992
Customer Revenues (Estimated) from:				
Rate Increases	**$21,827**	$28,138	**$ 8,087**	$ 3,644
Fuel Costs	**9,093**	(9,633)	**25,593**	11,512
Weather Effects (Heating)	**200**	1,236	**700**	5,722
Customer Consumption	**4,374**	(2,826)	**1,381**	1,098
Other	**(4,806)**	2,422	**(3,777)**	4,020
Total Change in Customer Revenues	**30,688**	19,337	**31,984**	25,996
Electric Sales to Other Utilities	**(9,180)**	(3,071)	**—**	—
Total Change in Operating Revenues	**$21,508**	$16,266	**$31,984**	$25,996

separation, of sales level fluctuations from revenue through the ERAM provisions, discussed under Regulatory Matters, and a gas normalization weather clause (see following paragraph) may mitigate the effect of abnormal weather conditions on earnings.

As part of the June 1992 rate decision, retail customers who use gas for spaceheating became subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing cycle month basis for the months of October through May, inclusive. The weather normalization adjustment for a billing cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1993 by approximately $1.2 million and in 1992 by approximately $1.8 million. The potential for such adjustments continues through June 1996 under the terms of the 1993 Rate Agreement.

Compared with the prior year, kilowatt-hour sales of energy to retail customers in 1993 climbed about one percent after being nearly flat in 1992. Electric demand for air conditioning usage had a significant impact on such sales in 1993 and 1992. During 1993, an increase in sales to both residential and commercial customers more than offset a decline in sales to industrial customers. Kilowatt-hour sales of energy in 1993 reflect the impact of approximately 2,200 new electric customers, which follows the addition of nearly 2,400 customers a year earlier.

Like many other electric utilities, the Company is encouraging energy efficiency through demand side management (DSM) programs. Objectives of the DSM programs include increasing the efficiency with which electricity is used and shifting electric load from peak to non-peak times, thus helping to save energy and delay the need to add new generating capacity. DSM programs include rebates for energy-efficient equipment, audits which focus on potential techniques for saving energy, consumer information and outreach, and design assistance to encourage energy-efficient new construction. In general, the Company is being allowed to amortize major DSM program expenditures over a five-year period. An incentive allowance (award) of approximately $0.6 million was provided for in the Company's rates based on the Company's DSM performance during 1992. Lost margins resulting from DSM activities are estimated and recovered in base rates. Variances between actual results and such estimates are recovered through fuel clause revenue adjustments, subject to certain incentive limitations.

Fluctuations in revenues from electric sales to other utilities are generally related to the Company's customer energy requirements, New York Power Pool energy market and transmission conditions and the availability of electric generation from Company facilities. Such revenues in 1992 and 1993 reflect the sale of energy at a lower average rate per megawatt hour, a result, in part, of competition and greater availability of energy. With more open access to transmission services as provided for under the Energy Act, the Company is examining alternative markets and procedures to meet what it believes will be increased competition for the sale of electric energy to other utilities.

The transportation of gas for large-volume customers who are able to purchase natural gas from sources other than the Company remains an important component of the Company's marketing mix. Company facilities are used to transport this gas, which amounted to 12.4 million dekatherms in 1993 and 12.6 million dekatherms in 1992. These purchases have caused decreases in customer revenues, with offsetting decreases in purchased gas expenses, but do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of gas, approximate the rates charged the Company's other gas service customers. Gas supplies transported in this manner are not included in Company therm sales, depressing reported gas sales to non-residential customers.

Therms of gas sold and transported, including unbilled sales, were nearly flat in 1993, following an 11.8 percent increase in 1992. These changes reflect, primarily, the effect of weather variations on therm sales to customers with space heating. If adjusted for normal weather conditions, residential gas sales would have decreased about 0.3 percent in 1993 over 1992, while nonresidential sales, including gas transported, would have decreased approximately 2.1 percent in 1993. The average use per residential gas customer, when adjusted for normal weather conditions was slightly down in 1993, following a modest increase in 1992. Total therms of gas transported increased in 1992 primarily as a result of higher sales to certain large industrial and municipal transportation customers. Sales to these customers in 1993 were down compared with 1992 sales.

Fluctuations in "Other" customer revenues shown in the table on page 24 for both comparison periods are largely the result of revenue taxes, deferred fuel costs, and miscellaneous revenues.

Operating Expenses

Compared with the prior year, operating expenses were up $40.2 million in 1993 after increasing $33.1 million in 1992. Approximately two-thirds of the increase in 1993 operating expenses resulted from higher gas purchased for resale costs. The increase in operating expenses for the 1993 comparison period was mitigated by the Company's continuing efforts to curtail increases in other operation expenses. Operating expenses are summarized in the table on page 27.

Energy Costs—Electric. An electric generation mix favoring less expensive nuclear fuel, compared with the cost of coal or oil, resulted in fuel expenses not increasing at the same rate as electric generation for the 1993 comparison period. For the 1992 comparison period, fuel expense for electric generation was lower by $16.7 million due, in part, to a refund to electric customers as described in the last paragraph under the heading New York State Public Service Commission. For both comparison periods, the average cost of coal declined.

Average rates for purchased electricity declined in 1993, after increasing in 1992. Such average rates partially offset an increase in kilowatt-hours purchased in 1993. For the 1992 comparison period, the increase in purchased electricity expense was caused by higher average rates during the year.

Energy Costs and Supply—Gas. As a result of the implementation of FERC Order 636, and the commencement of operation of the Empire State Pipeline, the Company now purchases all of its required gas supply directly from numerous producers and marketers under contracts containing varying terms and conditions. The Company holds firm transportation capacity on nine major pipelines, giving the Company access to the major gas-producing regions of North America. In addition to firm pipeline capacity, the Company also has obtained contracts for firm storage capacity on the CNG Transmission Corporation (CNG) system (10.4 billion cubic feet) and on the ANR Pipeline system (6.4 billion cubic feet) which are used to help satisfy its customers' winter demand requirements. With the commencement of operation of the Empire State Pipeline, the Company placed into operation its new Mendon gate station which is capable of supplying up to one-half of the Company's gas supply needs while also maintaining the various gate station interconnections with the CNG system that, prior to Empire, had supplied all of the Company's needs.

The transportation service to be provided by Empire was scheduled to phase in over 12 months, at which point the combined CNG and Empire transportation capacity would have exceeded the Company's current requirements. Therefore, the Company recently entered into a marketing agreement with CNG, pursuant to which CNG will assist the Company in obtaining permanent replacement customers for the transportation capacity the Company will not require. It may renegotiate its arrangements with CNG and/or Empire or it may negotiate assignment, on a permanent or temporary basis, of the transportation capacity that exceeds the requirements of its customers. In addition, under FERC rules, the Company may sell its excess transportation capacity in the market. While CNG has already secured letters of intent for a substantial portion of such capacity, whether and to what extent CNG and/or the Company can successfully negotiate the assignment or sale of the excess capacity, or at what price, cannot be determined at the present time. The retention of some or all of this excess transportation capacity may cause an increase in the Company's gas supply costs. This would be in addition to any increase caused by other aspects of the gas transportation restructuring.

As a result of the restructuring of the gas transportation industry by the FERC, there will be a number of changes in this aspect of the Company's business over the next several years. These changes, which will apply throughout the industry, will affect different companies differently and may result, at least initially, in increases in the gas transportation costs of the Company. The Company will also be required to pay a share of certain transition costs incurred by the pipelines as a result of the FERC restructuring. These include costs related to restructuring existing gas supply contracts, unrecovered gas costs that would otherwise have been billable to pipeline customers under previous regulation and other related costs deemed reasonable by the FERC. Although the final amounts of such transition costs are subject to continuing negotiations with several pipelines and ongoing pipeline filings requiring FERC approval, the Company expects such costs to range between $43.5 and $52.0 million. A substantial portion of such costs will be on the CNG system of which approximately $27 million was billed to the Company on December 3, 1993 payable over the following three years. The Company recorded a regulatory asset on its Balance Sheet and concurrently recognized a liability totaling approximately $43.5 million for estimated restructuring transition costs under FERC Order 636. The Company expects these transition costs to be recoverable in its rates.

The volume of gas purchased increased in both comparison periods primarily due to higher combined residential and commercial spaceheating sales, reflecting colder weather. The effect of higher-volume purchases was partially offset by lower average rates in 1992. In contrast to 1992, however, it was primarily an increase in these rates that pushed up the cost of gas purchased for resale in 1993. These higher rates reflect, in part, increased demand charges and, to a lesser extent, newly assessable gas service restructuring charges as a result of FERC Order 636.

Operating Expenses

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	1993	1992
Fuel for Electric Generation	$ (2,505)	$(16,729)
Purchased Electricity	1,857	2,023
Gas Purchased for Resale	25,593	11,512
Other Operation	8,757	18,184
Maintenance	(1,027)	(2,695)
Depreciation	(176)	478
Amortization of Other Plant	(675)	369
Taxes Charged to Operating Expenses		
Local, State and Other Taxes	2,640	10,603
Federal Income Tax	5,739	9,332
Total Change in Operating Expenses	$ 40,203	$ 33,077

Operating Expenses, Excluding Fuel. Other operation expenses rose over both comparison periods as shown by the table on page 27. The recording of certain postretirement benefits other than pensions, as required by Statement of Financial Accounting Standards No. 106 (SFAS-106) and discussed in the following paragraph, increased other operation expenses in 1992 by $4.9 million. Compared with a year earlier, other operation expenses in 1992 also reflect an increase of $3.0 million for transmission wheeling charges, $1.9 million due to increased amortization of costs associated with the Company's demand side management programs, and additional expenses of about $1.6 million associated with the Company's share of Nine Mile Two operation expenses. As stated earlier, the growth in other operation expenses was significantly less over the 1993 comparison period, a direct result, in part, of enhanced cost control efforts by the Company's employees. Compared with 1992, operating expenses associated with fire and liability insurance, transportation, materials and supplies, legal expenses, and the Company's share of Nine Mile Two operation expenses declined in 1993. The change in other operation expenses for the 1993 comparison period reflects primarily increased payroll costs and demand side management expenses.

During the first quarter of 1992, the Company adopted the Financial Accounting Standards Board's (FASB) SFAS-106 for financial accounting purposes. Among other things, SFAS-106 requires accrual accounting for postretirement benefits other than pensions. Based on accrual accounting required by SFAS-106, the Company's net periodic cost for postretirement benefits other than pension was $7.5 million in 1993 and $7.8 million in 1992. The PSC has allowed the Company revenues in rates based on SFAS-106. In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions." The Statement's provisions require, among other things, ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances. The Company adopted the Statement in 1993 for regulatory accounting purposes.

In November 1992, the FASB issued SFAS-112 entitled "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement requires the Company to recognize the obligation to provide postemployment benefits to former or inactive employees after employment but before retirement. Employers must accrue an obligation if the benefits are attributable to service already rendered, the benefits accumulate or vest, payment is probable, and the amounts can be reasonably estimated. The Company must adopt SFAS-112 not later than the first quarter of 1994. The Company is currently evaluating the impact of SFAS-112; however, based on studies the Company has performed to date, the adoption of SFAS-112 is not expected to have a material effect on the Company's financial condition or results of operations.

Reduced maintenance expense in both comparison periods was largely due to lower maintenance expenses incurred at nuclear production facilities and the effect of increased activity in 1991 associated with electric distribution facilities.

Despite an increase in depreciable plant in both comparison periods, depreciation and amortization of other plant fluctuated only moderately due mainly to a decrease in the depreciation and accrued decommissioning expenses related to the Ginna nuclear plant because of a three-year extension of its operating license and the completion in July 1992 of amortization of the Sterling property previously abandoned.

Taxes Charged to Operating Expenses. The increase in local, state and other taxes in both comparison periods resulted primarily from an increase in revenues combined with an increase in the revenue tax rate, and increased property tax rates and higher property assessments. The 1993 increase in local, state and other taxes was mitigated by the effect of the relative magnitude of these factors compared with 1992. The increase in these taxes for the 1992 comparison period reflects an adjustment for a one-half percent increase in the New York State gross revenue tax rate accounted for beginning in October 1991 retroactive to January 1, 1991.

During the first quarter of 1993, the Company adopted SFAS-109 entitled "Accounting for Income Taxes" issued by the FASB in February 1992. Among other things, SFAS-109 requires that a deferred tax liability be recognized on the balance sheet for tax differences previously flowed through to customers. The Company's adoption of SFAS-109 in the first quarter of 1993 did not have a material effect on the Company's results of operations although since then, reflection of a deferred tax liability, together with a corresponding regulatory asset, caused total assets and liabilities to increase significantly. See Note 2 of the Notes to Financial Statements for further discussion of SFAS-109 and an analysis of Federal income taxes.

In August 1993, the Revenue Reconciliation Act of 1993 (1993 Tax Act) was signed into law. Among other provisions, the 1993 Tax Act provides for a Federal corporate income tax rate of 35% (previously 34%) retroactive to January 1, 1993. The Company has adjusted its tax reserve balances to reflect this new rate. There was no earnings impact since the effects of the tax change have been deferred. The Company petitioned the PSC in late 1993 for recognition and recovery of this incremental tax liability which was not reflected in the provisions of its 1993 Rate Agreement. The Company's ability to recover this cost is dependent upon the PSC issuing a generic ruling on the treatment of the 1993 Tax Act.

Other Statement of Income Items

AFUDC variances are generally related to the amount of utility plant under construction and not included in rate base. AFUDC levels also reflect decreases in the gross rate to 3.90 percent effective September 1, 1993 from earlier rates of 4.50 percent, 5.50 percent, and 7.10 percent.

Variations in non-operating Federal income tax reflect mainly accounting adjustments related to retirement enhancement programs (see following paragraph), regulatory disallowances, and an employee performance incentive program (discussed below in this section).

Recorded under the caption Other Income and Deductions is the recognition of retirement enhancement programs designed to reduce overall labor costs which were implemented by the Company during the third and fourth quarters of 1993. A total of 173 employees elected to participate under these programs. The Company does not plan to replace any of those employees. Total estimated pretax costs of $8.2 million associated with these programs were recognized by the Company in its 1993 Statement of Income, thereby reducing after-tax earnings by approximately $.15 per share for the year. The Company estimates that the net pre-tax savings through 1997 resulting from these programs will amount to about $8.9 million.

Recorded under the caption Regulatory Disallowances is the recognition of the 1991 PSC order associated with the Company's fuel procurement practices, the 1992 PSC order related to the March 1991 ice storm, and the 1993 settlement with the PSC regarding certain alleged gas purchase undercharges, each discussed under the heading New York State Public Service Commission.

Other Income in 1992 includes $3.5 million of proceeds received in settlement of lawsuits filed against certain contractors involved in the construction of the Nine Mile Two nuclear plant. Non-cash earnings associated with the amortization of customer prepaid Nine Mile Two financing costs of $4.8 million in 1991, $2.5 million in 1992, and $1.2 million in 1993 are also included in Other Income. The decline in Other—Net Income and Deductions for the 1993 comparison period results mainly from the recognition of an employee performance incentive program for 1993. This program recognizes employees' achievements in meeting corporate goals and reducing expenses. Compared with a year earlier, Other—Net Income and Deductions also reflects lower miscellaneous interest revenues in 1993 and the recognition of

Energyline earnings (losses) upon consolidation with the accounts of the Company as discussed under Capital Requirements and Gas Operations.

Both mandatory and optional redemptions of certain higher-cost first mortgage bonds have helped to reduce long-term debt interest expense over the three-year period 1991–1993, despite the issuance of additional long-term debt in 1991 and 1992. In 1992, the effect of lower interest rates on debt expense was partially offset by increased short-term borrowings. The level of short-term debt borrowings decreased in 1993.

Earnings/Summary

Presented below is a table which summarizes the Company's Common Stock earnings on a per-share basis. Certain non-recurring items and their effect on earnings per share have been identified in this table. Compared with a year earlier, earnings per share were up in 1993 and 1992 despite the effect of a public issuance of Common Stock in each year. Future earnings will be affected, in part, by the Company's success in achieving demand side management and other incentive goals, as well as controlling operating and capital costs, within levels provided for in rates under the terms of the 1993 Rate Agreement.

In December 1992 the Company announced a quarterly dividend increase from $.42 to $.43 per share of Common Stock payable in January 1993. Subsequently, in December 1993 the Company announced a new quarterly dividend rate of $.44 per share payable in January 1994. The Company's Charter provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company. Accordingly, dividend payments are dependent on future earnings, in addition to financial requirements and other factors.

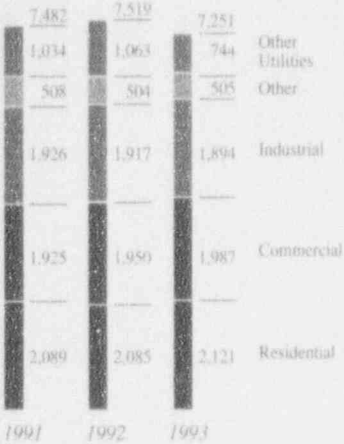
Earnings per Share—Summary

(Dollars per Share)	1993	1992	1991
Earnings per Share Before Non-recurring Items	$2.19	$1.91	$1.81
Non-recurring Items			
Gas Under-recovery Writeoff	(.04)		
Retirement Enhancement Programs	(.15)		
Nine Mile Two Litigation Proceeds		.10	
Ice Storm Disallowance		(.15)	
Fuel Procurement Audit			(.21)
Total Non-recurring Items	$(.19)	$(.05)	$(.21)
Reported Earnings per Share	$2.00	$1.86	$1.60

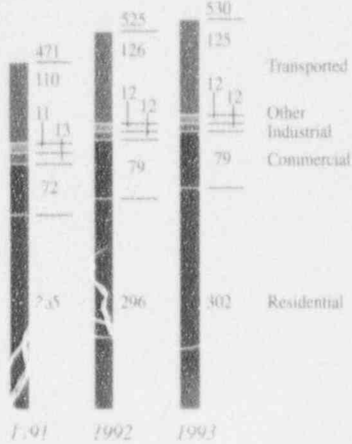
Financial Reports

Financial Profile

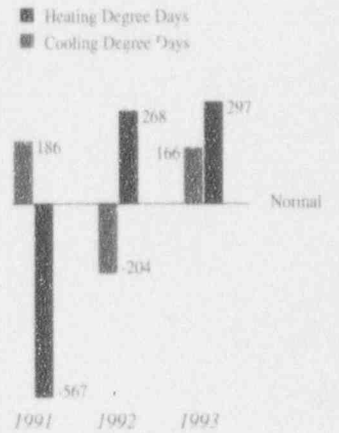
Electric Market Profile
(thousands of mwh sold)



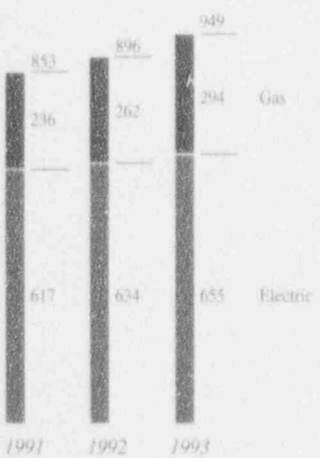
Gas Market Profile
(millions of therms sold and transported)



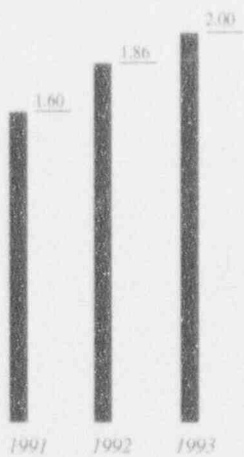
Degree Day Variations From Normal



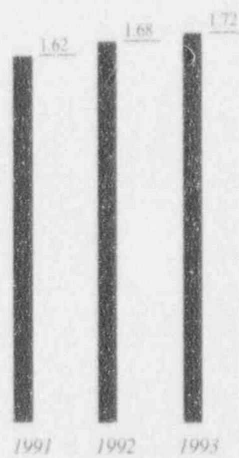
Operating Revenues
(millions of dollars)



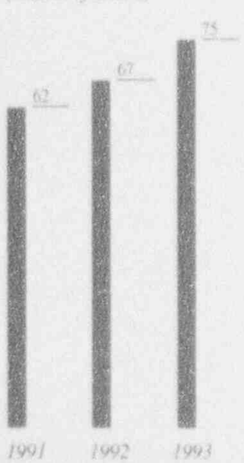
Earnings Per Share Of Common Stock
(dollars)



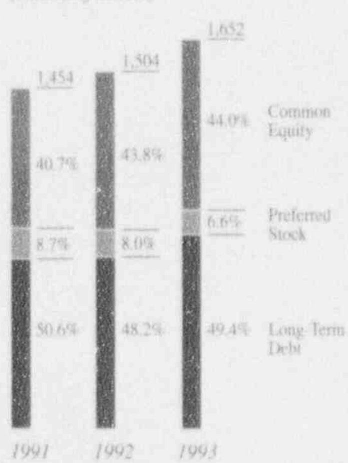
Dividends Per Share Of Common Stock
(dollars)



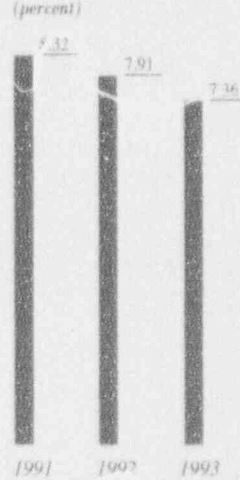
Retained Earnings At December 31
(millions of dollars)



Capitalization At December 31
(millions of dollars)



Embedded (Annual) Cost Of Long-Term Debt At Year End
(percent)



Consolidated Statement of Income

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Operating Revenues			
Electric	$ 638,955	$ 608,267	$ 588,930
Gas	293,708	261,724	235,728
	932,663	869,991	824,658
Electric sales to other utilities	16,361	25,541	28,612
Total Operating Revenues	949,024	895,532	853,270
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	45,871	48,376	65,105
Purchased electricity	31,563	29,706	27,683
Gas purchased for resale	166,884	141,291	129,779
Total Fuel Expenses	244,318	219,373	222,567
Operating Revenues Less Fuel Expenses	704,706	676,159	630,703
Other Operating Expenses			
Operations excluding fuel expenses	235,381	226,624	208,440
Maintenance	61,693	62,720	65,415
Depreciation and amortization	84,177	85,028	84,181
Taxes—local, state and other	126,892	124,252	113,649
Federal income tax	49,330	43,591	34,259
Total Other Operating Expenses	557,473	542,215	505,944
Operating Income	147,233	133,944	124,759
Other Income and Deductions			
Allowance for other funds used during construction	153	164	675
Federal income tax	9,827	4,195	4,580
Pension Plan Curtailment	(8,179)	—	—
Regulatory disallowances	(1,953)	(8,215)	(10,000)
Other, net	(7,074)	6,155	6,078
Total Other Income and (Deductions)	(7,226)	2,299	1,333
Income Before Interest Charges	140,007	136,243	126,092
Interest Charges			
Long term debt	56,451	60,810	63,918
Other, net	6,707	7,178	7,082
Allowance for borrowed funds used during construction	(1,714)	(2,184)	(2,905)
Total Interest Charges	61,444	65,804	68,095
Net Income	78,563	70,439	57,997
Dividends on Preferred Stock	7,300	8,290	6,963
Earnings Applicable to Common Stock	$ 71,263	$ 62,149	$ 51,034
Weighted Average Number of Shares for Period (000's)	35,599	33,258	31,794
Earnings per Common Share	$ 2.00	$ 1.86	$ 1.60

Consolidated Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Balance at Beginning of Period	$ 66,968	$ 61,515	$ 62,542
Add			
Net Income	78,563	70,439	57,997
Adjustment Associated with Stock Redemption	(933)	—	—
Total	144,598	131,954	120,539
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock	7,300	8,290	6,963
Common stock	62,172	56,696	52,061
Total	69,472	64,986	59,024
Balance at End of Period	$ 75,126	$ 66,968	$ 61,515

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

Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1993	1992
Assets		
Utility Plant		
Electric	$ 2,234,530	$ 2,175,255
Gas	356,484	341,466
Common	125,428	123,034
Nuclear fuel	174,357	158,826
	2,890,799	2,798,581
Less: Accumulated depreciation	1,190,801	1,125,502
Nuclear fuel amortization	144,282	127,615
	1,555,716	1,545,464
Construction work in progress	112,750	83,834
Net Utility Plant	1,668,466	1,629,298
Current Assets		
Cash and cash equivalents	2,327	1,759
Accounts receivable, net of allowance for doubtful accounts: 1993—$600; 1992—$500	104,753	92,292
Unbilled revenue receivable	61,330	60,184
Materials and supplies, at average cost		
Fossil fuel	5,983	12,273
Construction and other supplies	13,644	13,130
Gas stored underground	38,989	9,998
Prepayments	21,563	19,985
Total Current Assets	248,589	209,621
Investment in Empire	38,560	9,846
Deferred Debits		
Regulatory Asset—Income Taxes	241,741	—
Deferred finance charges—Nine Mile Two	19,242	20,492
Deferred ice storm charges	21,621	24,197
Uranium enrichment decommissioning deferral	23,421	28,613
Nuclear generating plant decommissioning fund	38,930	29,549
Nine Mile Two deferred costs	34,513	34,300
FERC 636 Transition Costs	41,265	—
Unamortized debt expense	19,326	13,553
Other	61,956	49,972
Total Deferred Debits	502,015	200,676
Total Assets	$ 2,457,630	$ 2,049,441
Capitalization and Liabilities		
Capitalization		
Long term debt—mortgage bonds	$ 655,731	$ 566,980
—promissory notes	91,900	91,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	42,000	54,000
Common shareholders' equity		
Common stock	652,172	591,532
Retained earnings	75,126	66,968
Total Common Shareholders' Equity	727,298	658,500
Total Capitalization	1,583,929	1,438,380
Long Term Liabilities (Department of Energy):		
Nuclear waste disposal	68,055	65,989
Uranium enrichment decommissioning	21,749	28,613
Total Long Term Liabilities	89,804	94,602
Current Liabilities		
Long term debt due within one year	21,250	110,250
Preferred stock redeemable within one year	6,000	6,000
Note Payable—Empire	29,600	—
Short term debt	68,100	50,800
Accounts payable	52,596	40,578
Dividends payable	18,066	17,035
Taxes accrued	6,472	13,743
Interest accrued	12,955	15,461
Other	19,491	13,409
Total Current Liabilities	234,530	267,276
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	425,648	171,673
Deferred finance charges—Nine Mile Two	19,242	20,492
Pension costs accrued	31,919	20,278
Other	72,558	36,740
Total Deferred Credits and Other Liabilities	549,367	249,183
Commitments and Other Matters (Note 10)	—	—
Total Capitalization and Liabilities	$ 2,457,630	$ 2,049,441

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

Consolidated Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Cash Flow from Operations			
Net income	$ 78,563	$ 70,439	$ 57,997
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	84,177	85,028	84,181
Amortization of nuclear fuel	18,861	18,803	23,606
Deferred fuel—electric	(2,072)	2,543	4,122
Deferred fuel—gas	(11,500)	4,896	2,166
Deferred income taxes	15,232	10,466	9,124
Allowance for funds used during construction	(1,867)	(2,348)	(3,580)
Unbilled revenue, net	(5,107)	(6,631)	(8,931)
Ice storm costs	2,576	12,234	(36,431)
Nuclear generating plant decommissioning	(9,381)	(10,328)	(15,581)
Changes in certain current assets and liabilities:			
Accounts receivable	(12,461)	(8,239)	(4,773)
Materials and supplies—fossil fuel	6,290	(1,507)	7,506
—construction and other supplies	(514)	(591)	(315)
Gas stored underground	(28,991)	(2,942)	(7,057)
Taxes accrued	(7,271)	1,693	1,444
Accounts payable	12,018	(13,404)	6,914
Interest accrued	(2,506)	(852)	1,722
Other current assets and liabilities, net	6,113	(2,528)	(592)
Other, net	10,966	(5,832)	(2,075)
Total Operating	$ 153,126	$ 150,900	$ 119,447
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$ (125,744)	$ (115,792)	$ (114,579)
Nuclear fuel additions	(15,530)	(11,763)	(13,058)
Less: Allowance for funds used during construction	1,867	2,348	3,580
Additions to Utility Plant	(139,407)	(125,207)	(124,057)
Investment in Empire—net	884	(9,846)	—
Other, net	(1,907)	490	(685)
Total Investing	$ (140,430)	$ (134,563)	$ (124,742)
Cash Flow from Financing Activities			
Proceeds from:			
Sale/Issue of common stock	$ 61,254	$ 63,928	$ 13,446
Sale of preferred stock	—	—	30,000
Sale of long term debt, mortgage bonds	200,000	160,500	100,000
Short term borrowings	17,300	(8,700)	17,100
Retirement of long term debt	(200,249)	(160,000)	(92,334)
Retirement of preferred stock	(12,000)	—	—
Capital stock expense	(615)	(1,735)	(495)
Discount and expense of issuing long term debt	(7,909)	(6,368)	(3,310)
Dividends paid on preferred stock	(7,548)	(8,290)	(6,396)
Dividends paid on common stock	(60,893)	(55,216)	(51,308)
Other, net	(1,468)	(185)	(464)
Total Financing	$ (12,128)	$ (16,066)	$ 6,239
Increase in cash and cash equivalents	$ 568	$ 271	$ 944
Cash and cash equivalents at beginning of year	$ 1,759	$ 1,488	$ 544
Cash and cash equivalents at end of year	$ 2,327	$ 1,759	$ 1,488

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 60,852	$ 64,431	$ 63,848
Income taxes paid	$ 32,779	$ 22,911	$ 20,399

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

Notes to Financial Statements

Note 1. Summary of Accounting Principles

General.

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

In June 1988, the Board of Directors authorized the creation of Utilicom, Inc. as a wholly owned subsidiary. Utilicom develops and markets computer software to assist customers in complying with state and federal environmental and safety regulations. On August 31, 1993, the Company sold the assets of Utilicom and liquidated the subsidiary. The subsidiary activity prior to and including disposition was insignificant to the Company's financial position and results of operation.

In April 1990, the Board of Directors authorized the creation of Energyline Corporation, a wholly owned subsidiary, which was incorporated in July 1992. Energyline was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. On November 1, 1993 Empire commenced service to the Company's gas distribution facilities. The Company has authority to invest up to $20 million in Empire. In June 1993 Empire secured a $150 million credit agreement, the proceeds of which are to finance approximately 75 percent of the total construction cost and initial operating expenses. Energyline is obligated to pay up to 20% of the balance outstanding subject to a commitment of $9.7 million under the credit agreement. Excluding the loan commitment, at December 31, 1993 the Company had invested a net amount of $10.2 million in Energyline.

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

Rates and Revenue.

Revenue is recorded on the basis of meters read. In addition, the Company records an estimate of unbilled revenue for service rendered subsequent to the meter-read date through the end of the accounting period.

Tariffs for electric and gas service include fuel cost adjustment clauses which adjust the rates monthly to reflect changes in the actual average cost of fuels. The electric fuel adjustment provides that ratepayers and the Company will share the effects of any variation from forecast monthly unit fuel costs on a 50%/50% basis up to a $5.6 million cumulative annual gain or loss to the Company. Thereafter, 100 percent of additional fuel clause adjustment amounts are assigned to customers. The electric fuel cost adjustment also provides that any variation from forecast margins below $7.1 million or above $8.5 million on sales to electric utilities be shared with retail customers on a 50%/50% basis.

In addition, there is a similar 50%/50% sharing process of variances from forecasted margins derived from sales and the transportation of privately owned gas to large customers that can use alternate fuels.

Under the Company's Electric Revenue Assurance Mechanism (ERAM), which was established in the 1993 multi-year rate settlement, any variations between actual margins and the established targets may be recovered from or returned to customers. Other performance incentives or penalties were established in the settlement and under some circumstances could be recognized periodically. However, through December 31, 1993, no amount was recognized as recoverable or payable to customers.

Retail customers who use gas for spaceheating are subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing month basis for the months of October through May, inclusive. The weather normalization adjustment for a billing cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1993 and 1992 by approximately $1.2 million and

$1.8 million respectively. These adjustments will continue through June 1996 in accordance with the 1993 multi-year rate settlement agreement.

Deferred Fuel Costs.

The Company practices fuel cost deferral accounting as described above. A reconciliation of recoverable gas costs with gas revenues is done annually as of August 31, and the excess or deficiency is refunded to or recovered from the customers during a subsequent twelve-month period beginning in December. These deferred fuel costs are included as a component of unbilled revenues.

Utility Plant, Depreciation and Amortization.

The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect charges such as engineering and supervision, and is recorded at original cost. The Company capitalizes an allowance for funds used during construction approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. Replacement of minor items of property is included in maintenance expenses. Costs of depreciable units of plant retired are eliminated from utility plant accounts, and such costs, plus removal expenses, less salvage, are charged to the accumulated depreciation reserve.

Depreciation in the financial statements is provided on a straight-line basis at rates based on the estimated useful lives of property, which have resulted in provisions of 2.9%, 2.9% and 3.3% per annum of average depreciable property in 1993, 1992 and 1991, respectively. The decrease in depreciation provision percentages from 1991 to 1992 is principally the result of a 3½ year extension of the Ginna Nuclear Plant license term and lengthening estimated useful lives at other property.

Nuclear Fuel Disposal Costs.

The Nuclear Waste Policy Act (Act) of 1982, as amended, requires the United States Department of Energy (DOE) to establish a nuclear waste disposal site and to take title to nuclear waste. A permanent DOE high-level nuclear waste repository is not expected to be operational before the year 2010. The DOE is pursuing efforts to establish a monitored retrievable interim storage facility which may allow it to take title to and possession of nuclear waste prior to the establishment of a permanent repository. The Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected by the Company in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be $68.1 million at December 31, 1993. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.001) per KWH of nuclear energy generated and sold. This charge is currently being collected from customers and paid to the DOE pursuant to PSC authorization. The Company expects to utilize on-site storage for all spent or retired nuclear fuel assemblies until an interim or permanent nuclear disposal facility is operational.

Nuclear Decommissioning Costs.

Decommissioning costs (costs to take the plant out of service in the future) for the Company's Ginna Nuclear Plant are estimated to be approximately $150.7 million, and those for the Company's 14% share of Nine Mile Two's decommissioning costs are estimated to be approximately $34.3 million (January 1993 dollars). Through December 31, 1993, the Company has accrued and recovered in rates $61.2 million for this purpose and is currently accruing and recovering decommissioning costs at a rate of approximately $8.9 million per year based on the use of a combination of internal and external sinking funds. (See Note 10.)

(Note 1 continued on page 38)

(continued from page 37)

The decommissioning costs, which form the basis for current accruals, were derived from the record of the Company's prior rate proceeding (PSC Opinion 93-19, issued August 1993) and were estimated principally by reference to a formula prescribed by the NRC for the purpose of providing for adequate funding at the time of the decommissioning.

Uranium Enrichment Decontamination and Decommissioning Fund.

As part of the National Energy Act (Act) issued in October 1992, utilities with nuclear generating facilities are assessed an annual fee payable over 15 years to pay for the decommissioning of Federally owned uranium enrichment facilities. The assessments for Ginna and Nine Mile Two are estimated to total $24.1 million, excluding inflation and interest. The first installment of $1.6 million was paid in 1993 and recovered through the fuel adjustment clause. A liability has been recognized on the financial statements along with a corresponding regulatory asset. The Company believes that the full amount of the assessment will be recoverable in rates as described in the Act.

FERC Order 636.

Under this order, gas supply and pipeline companies are allowed to pass restructuring and transition costs associated with the implementation of the order on to their customers. The Company, as a customer, has estimated a total of $43.5 million which will be paid to its suppliers. A regulatory asset and related deferred credit have been established on the balance sheet to account for these estimated costs. Approximately $2.2 million of these costs were paid during 1993 to various suppliers, and have been included in purchased gas costs (see Note 10).

Allowance for Funds Used During Construction.

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

The rates approved by the PSC for purposes of computing AFUDC were: 3.9% from September 1, 1993 through December 31, 1993; 4.5% from September 1, 1992 through August 31, 1993; 5.5% from April 1, 1992 through August 31, 1992; 7.1% from July 1, 1991 through March 31, 1992; 8.6% from February 1, 1991 through June 30, 1991; 9.6% from January 1, 1991 through January 31, 1991.

In 1984, the Company discontinued accruing AFUDC on a portion of its investment in Nine Mile Two for which a cash return was allowed. Amounts were accumulated in deferred debit and credit accounts equal to the amount of AFUDC which was no longer accrued. The balance in the deferred credit account was intended to reduce future cash revenue requirements over a period substantially shorter than the life of Nine Mile Two, and the balance in the deferred debit account would then be collected from customers over a longer period of time. The current balances of $19.2 million are expected to remain on the Company's books for future application by the PSC as a rate moderator.

Federal Income Tax.

For income tax purposes, depreciation is generally computed using the most liberal methods permitted. The resulting tax reductions are offset by provisions for deferred income taxes only to the extent ordered or permitted by regulatory authorities.

Statement of Financial Accounting Standards (SFAS) 109, Accounting for Income Taxes, was adopted by the Company during the first quarter of 1993. SFAS-109 requires that a deferred tax liability must be recognized on the balance sheet for tax differences previously flowed through to customers. Substantially all of these flow-through adjustments relate to property plant and equipment and related investment tax credits and will be amortized consistent with the depreciation of these accounts. The net amount of the additional liability at December 31, 1993 was $241 million. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

SFAS-109 also requires that a deferred tax liability or asset be adjusted in the period of enactment for the effect of changes in tax laws or rates. During the year the statutory income tax rate was increased one percent to 35%. This resulted in increases of $.6 million and $1.3 million for current and deferred tax liabilities, respectively. There was no earnings impact since the effects of the tax change have been deferred for future recovery.

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

Retirement Health Care and Life Insurance Benefits.

The Company provides certain health care and life insurance benefits for retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. These and similar benefits for active employees are provided through insurance policies whose premiums are based upon the experience of benefits actually paid.

In December 1990, the FASB issued SFAS-106 entitled "Accounting for Postretirement Benefits Other than Pensions" effective for fiscal years beginning after December 15, 1992. Among other things, SFAS-106 requires accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. The Company adopted this accounting practice in 1992.

In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions". The Statement's provisions require, among other things, ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances. The effects of applying the ten year amortization of actuarial gains were deferred.

Postemployment Benefits.

In November 1992, the FASB issued SFAS-112 entitled "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement requires the Company to recognize the obligation to provide post-employment benefits to former or inactive employees after employment but before retirement. The Company must adopt SFAS-112 not later than the first quarter of 1994. The Company is currently evaluating the impact of SFAS-112; however, based on studies the Company has performed to date, the adoption of SFAS-112 is not expected to have a material effect on the Company's financial condition or results of operations.

Earnings Per Share.

Earnings applicable to each share of common stock are based on the weighted average number of shares outstanding during the respective years.

Note 2. Federal Income Taxes

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

(Thousands of Dollars)	1993	1992	1991
Charged to operating expense:			
Current	$33,453	$36,101	$28,766
Deferred	15,877	7,490	5,493
Total	49,330	43,591	34,259
Charged (Credited) to other income:			
Current	(9,182)	(7,171)	(8,211)
Deferred	(645)	2,976	3,631
Total	(9,827)	(4,195)	(4,580)
Total Federal income tax expense	$39,503	$39,396	$29,679

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

(Thousands of Dollars)	1993		1992		1991	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$ 78,563		$ 70,439		$57,997	
Add: Federal income tax expense	39,503		39,396		29,679	
Income before Federal income tax	$118,066		$109,835		$87,676	
Computed tax expense	$ 41,323	35.0	$ 37,344	34.0	$29,810	34.0
Increases (decreases) in tax resulting from:						
Difference between tax depreciation and amount deferred	6,337	5.4	6,775	6.2	5,606	6.4
Investment tax credit	(2,432)	(2.1)	(2,426)	(2.2)	(2,432)	(2.8)
Miscellaneous items, net	(5,725)	(4.8)	(2,297)	(2.1)	(3,305)	(3.7)
Total Federal income tax expense	$ 39,503	33.5	$ 39,396	35.9	$29,679	33.9

A summary of the components of the net deferred tax liability is as follows:

(Thousands of Dollars)	1993	1992
Nuclear decommissioning	$(11,518)	$(13,087)
Nine Mile disallowance	(15,200)	(19,569)
Alternative minimum tax	(27,908)	(27,611)
Accelerated depreciation	164,821	174,237
Investment tax credit	34,305	55,206
Ice storm	5,642	6,519
Depreciation and ITC previously flowed through	246,127	—
Other	29,379	(4,022)
Total	$425,648	$171,673

In 1993, the regulatory asset recognized by the Company as a result of adopting SFAS No. 109 is attributed to $222 million in depreciation, $18 million to property taxes, $18 million of deferred finance charges—Nine Mile Two and $4 million of miscellaneous items offset by $21 million attributed to investment tax credits.

Note 3. Pension Plan and Other Retirement Benefits

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

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

(Millions)	1993	1992
Accumulated benefit obligation, including vested benefits of $286.1 in 1993 and $249.6 in 1992	$(309.3)*	$(268.1)*
Projected benefit obligation for service rendered to date	$(429.5)*	$(378.0)*
Less—Plan assets at fair value, primarily listed stocks and bonds	490.3	449.9
Plan assets in excess of projected benefits	60.8	71.9
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	(110.6)	(102.4)
Prior service cost not yet recognized in net periodic pension cost	13.7	5.4
Unrecognized net obligation at December 31	4.2	4.8
Pension costs accrued	$ (31.9)**	$(20.3)

*Actuarial present value

**Includes $9.2 million pension plan curtailment charge.

Net pension cost included the following components:

(Millions)	1993	1992	1991
Service cost—benefits earned during the period	$ 8.7	$ 8.8	$ 7.1
Interest cost on projected benefit obligation	30.0	27.9	26.4
Actual return on plan assets	(60.2)	(35.1)	(58.6)
Net amortization and deferral	24.3	5.5	33.1
Net periodic pension cost	$ 2.8	$ 7.1	$ 8.0

The projected benefit obligation at December 31, 1993 and 1992 assumed discount rates of 7¼ percent and 7¾ percent, respectively and long-term rate of increase in future compensation levels of 6 percent and 6½ percent, respectively. The assumed long-term rate of return on plan assets for 1993 and 1992 was 8½ percent. The unrecognized net obligation is being amortized over 15 years beginning January 1986.

In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions" (Statement). The 1993 pension cost reflects adoption of the Statement's provisions which, among other things, requires ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits to retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees are eligible provided that they retire as employees of the Company. In 1993, the health care benefit consisted of a contribution of up to $175 per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay. In addition, certain employees and retirees, employed by the Company at December 31, 1982, are entitled to a Special Group Life benefit providing a death benefit equal to the employee's December 31, 1982 pay.

(Note 3 continued on page 42)

(continued from page 41)

The Company adopted SFAS-106, "Accounting for Postretirement Benefits Other than Pensions" as of January 1, 1992 for financial accounting purposes. Subsequently, with the issuance of the Statement referenced above, the Company's application of SFAS-106 will extend to ratemaking purposes as well. The Company has elected to amortize the unrecognized, unfunded Accumulated Postretirement Benefit Obligation at January 1, 1992 over twenty years as provided by SFAS-106. The Company intends to continue funding these benefits on a pay-as-you-go basis.

The plans' funded status reconciled with the Company's balance sheet is as follows:

(Millions)	1993	1992
Accumulated postretirement benefit obligation:		
Retired employees	**$(39.9)**	$(35.3)
Active employees	**(24.9)**	(23.6)
	$(64.8)	$(58.9)
Less—Plan assets at fair value	**0.0**	0.0
Accumulated postretirement benefit obligation (in excess of) less than fair value of assets	**(64.8)**	(58.9)
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	**2.9**	0.0
Prior service cost not yet recognized in net periodic pension cost	**1.7**	0.0
Unrecognized net obligation at December 31	**50.7**	53.6
Accrued postretirement benefit cost	**$ (9.5)**	$ (5.3)

Net periodic postretirement benefit cost included the following components:

(Millions)	1993	1992
Service cost—benefits attributed to the period	**$ 0.7**	$ 0.7
Interest cost on accumulated postretirement benefit obligation	**4.6**	4.3
Actual return on plan assets	**0.0**	0.0
Net amortization and deferral	**2.2**	2.8
Net periodic postretirement benefit cost	**$ 7.5**	$ 7.8

The Accumulated Postretirement Benefit Obligation at December 31, 1993 and 1992 assumed discount rates of 7¼ percent and 7¾ percent, respectively and long-term rate of increase in future compensation levels of 6 percent and 6½ percent, respectively.

Note 4. Departmental Financial Information

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

(Thousands of Dollars)	1993	1992	1991
Electric			
Operating Information			
Operating revenues	$ 655,316	$ 633,808	$ 617,542
Operating expenses, excluding provision for income taxes	486,951	482,968	478,101
Pretax operating income	168,365	150,840	139,441
Provision for income taxes	43,845	38,046	31,390
Net operating income	$ 124,520	$ 112,794	$ 108,051
Other Information			
Depreciation and amortization	$ 72,326	$ 73,213	$ 72,746
Nuclear fuel amortization	$ 18,861	$ 18,803	$ 23,606
Capital expenditures	$ 112,022	$ 100,974	$ 97,294
Investment Information			
Identifiable assets (a)	$1,978,009	$1,671,492	$1,607,210
Gas			
Operating Information			
Operating revenues	$293,708	$261,724	$ 235,728
Operating expenses, excluding provision for income taxes	265,510	235,029	216,151
Pretax operating income	28,198	26,695	19,577
Provision for income taxes	5,485	5,545	2,869
Net operating income	$ 22,713	$ 21,150	$ 16,708
Other Information			
Depreciation and amortization	$ 11,851	$ 11,815	$ 11,435
Capital expenditures	$ 27,385	$ 24,231	$ 26,763
Investment Information			
Identifiable assets (a)	$491,563	$354,528	$ 325,451

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

Note 5. Jointly-Owned Facilities

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

	Oswego Unit No. 6	Nine Mile Point Nuclear Unit No. 2
Net megawatt capacity	850	1,080
RG&E's share—megawatts	204	151
—percent	24	14
Year of completion	1980	1988
	Millions of Dollars at December 31, 1993	
Plant In Service Balance	$97.7	$869.8
Accumulated Provision For Depreciation	$32.0	$441.1
Plant Under Construction	$ 0.5	$ 12.4

The Plant in Service and Accumulated Provision for Depreciation balances for Nine Mile Point Nuclear Unit No. 2 shown above have been increased by the disallowed costs of $374.3 million. Such costs, net of income tax effects, were previously written off in 1987 and 1989.

Note 6. Long Term Debt

First Mortgage Bonds

%	Series	Due	(Thousands) Principal Amount December 31 1993	1992
4⅝	U	Sept. 15, 1994	**$ 16,000**	$ 16,000
5.30	V	May 1, 1996	**18,000**	18,000
6¼	W	Sept. 15, 1997	**20,000**	20,000
6.7	X	July 1, 1998	**30,000**	30,000
8.00	Y	Aug. 15, 1999	**30,000**	30,000
9⅝	Z	Sept. 1, 2000	**—**	30,000
9¼	BB	June 15, 2006	**—**	50,000
8⅜	CC	Sept. 15, 2007	**50,000**	50,000
9½	DD	Dec. 1, 2003	**—**	40,000
6½	EE (a)	Aug. 1, 2009	**10,000**	10,000
10.95	FF	Feb. 15, 2005	**2,750**	5,500
13¾	JJ	June 15, 1999	**15,000**	17,500
8.6	LL	Aug. 1, 1993	**—**	75,000
8⅜	OO (a)	Dec. 1, 2028	**25,500**	25,500
9⅜	PP	Apr. 1, 2021	**100,000**	100,000
8¼	QQ (b)	Mar. 15, 2002	**100,000**	100,000
6.35	RR (a)	May 15, 2032	**10,500**	10,500
6.50	SS (a)	May 15, 2032	**50,000**	50,000
7.00	(b) (c)	Jan. 14, 2000	**30,000**	—
7.15	(b) (c)	Feb. 10, 2003	**39,000**	—
7.13	(b) (c)	Mar. 3, 2003	**1,000**	—
7.64	(c)	Mar. 15, 2023	**33,000**	—
7.66	(c)	Mar. 15, 2023	**5,000**	—
7.67	(c)	Mar. 15, 2023	**12,000**	—
6.375	(b) (c)	July 30, 2003	**40,000**	—
7.45	(c)	July 30, 2023	**40,000**	—
			677,750	678,000
Net bond discount			**(769)**	(770)
Less: Due within one year			**21,250**	110,250
Total			**$655,731**	$566,980

(a) The Series EE, Series OO, Series RR and Series SS First Mortgage Bonds equal the principal amount of and provide for all payments of principal, premium and interest corresponding to the Pollution Control Revenue Bonds, Series A, Series C, and Pollution Control Refunding Revenue Bonds, Series 1992 A, Series 1992 B (Rochester Gas and Electric Corporation Projects), respectively, issued by the New York State Energy Research and Development Authority through a participation agreement with the Company. Payment of the principal of, and interest on the Series 1992 A and Series 1992 B Bonds are guaranteed under a Bond Insurance Policy by Municipal Bond Investors Assurance Corporation. The Series EE Bonds are subject to a mandatory sinking fund beginning August 1, 2000 and each August 1 thereafter. Nine annual deposits aggregating $3.2 million will be made to the sinking fund, with the balance of $6.8 million principal amount of the bonds becoming due August 1, 2009.

(b) The Series QQ First Mortgage Bonds and 7%, 7.15%, 7.13% and 6.375% medium-term notes described below are generally not redeemable prior to maturity.

(c) In 1993 the Company issued $200 million under a medium-term note program entitled "First Mortgage Bonds, Designated Secured Medium-Term Notes, Series A" with maturites that range from seven years to thirty years.

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

Sinking and improvement fund requirements aggregate $333,540 per annum under the First Mortgage, excluding mandatory sinking funds of individual series. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1992 and 1993 requirements were met by certification of additional property.

Sinking fund requirements and bond maturities for the next five years are:

(Thousands)	1994	1995	1996	1997	1998
Series FF (d)	$ 2,750				
Series JJ (e)	2,500	$2,500	$ 2,500	$ 2,500	$ 2,500
Series U	16,000				
Series V			18,000		
Series W				20,000	
Series X					30,000
	$21,250	$2,500	$20,500	$22,500	$32,500

(d) The Series FF First Mortgage Bonds are subject to a mandatory sinking fund of $2.75 million annually each February 15.

(e) The Series JJ First Mortgage Bonds are subject to a mandatory sinking fund of $2.5 million annually each June 15.

Promissory Notes

		(Thousands) December 31	
Issued	Due	**1993**	1992
November 15, 1984 (f)	October 1, 2014	**$51,700**	$51,700
December 5, 1985 (g)	November 15, 2015	**40,200**	40,200
Total		**$91,900**	$91,900

(f) The $51.7 million Promissory Note was issued in connection with NYSERDA's Floating Rate Monthly Demand Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1984. This obligation is supported by an irrevocable Letter of Credit expiring October 15, 1994. The interest rate on this note for each monthly interest payment period will be based on the evaluation of the yields of short term tax-exempt securities at par having the same credit rating as said Series 1984 Bonds. The average interest rate was 2.19% for 1993, 2.74% for 1992 and 4.32% for 1991. The interest rate will be adjusted monthly unless converted to a fixed rate.

(g) The $40.2 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1985. This obligation is supported by an irrevocable Letter of Credit expiring November 30, 1996. The annual interest rate was adjusted to 4.50% effective November 15, 1991, to 3.10% effective November 15, 1992 and to 2.75% effective November 15, 1993. The interest rate will be adjusted annually unless converted to a fixed rate.

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

Based on an estimated borrowing rate at year-end 1993 of 6.68% for long term debt with similar terms and average maturities (14 years), the fair value of the Company's long term debt outstanding (including Promissory Notes as described above) is approximately $816 million at December 31, 1993.

Note 7. Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,150,000*
Preferred Stock (cumulative)	25	4,000,000	—
Preference Stock	1	5,000,000	—

*See below for mandatory redemption requirements

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

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

%	Series	Shares Outstanding December 31, 1993	(Thousands) December 31 1993	1992	Optional Redemption (per share)#
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4¾	I	60,000	6,000	6,000	101
4.10	J	50,000	5,000	5,000	102.5
4.95	K	60,000	6,000	6,000	102
4.55	M	100,000	10,000	10,000	101
7.50	N	200,000	20,000	20,000	102
Total		670,000	$67,000	$67,000	

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

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

%	Series	Shares Outstanding December 31, 1993	(Thousands) December 31 1993	1992	Optional Redemption (per share)
8.25	R	180,000	$18,000	$30,000	$102.00 Before 3/1/94+
7.45	S	100,000	10,000	10,000	Not applicable
7.55	T	100,000	10,000	10,000	Not applicable
7.65	U	100,000	10,000	10,000	Not applicable
		480,000	$48,000	$60,000	
Less: Due within one year		60,000	6,000	6,000**	
Total		420,000	$42,000	$54,000	

+Thereafter at $100.00
**Excludes $6 million optional redemption effective March 1, 1993

Mandatory Redemption Provisions.

In the event the Company should be in arrears in the sinking fund requirement, the Company may not redeem or pay dividends on any stock subordinate to the Preferred Stock.

Series R. Mandatory redemption of 60,000 shares per year at $100 per share commenced on March 1, 1993 for Series R and on each March 1 thereafter, so long as any shares remain outstanding. In addition, the Company has the non-cumulative right to redeem up to an additional 60,000 shares on the same terms and dates applicable to the mandatory sinking fund redemptions. The Company redeemed 120,000 shares on March 1, 1993 and the Company has the right to redeem up to the remaining 180,000 shares on March 1, 1994.

Series S, Series T, Series U. All of the shares are subject to redemption pursuant to mandatory sinking funds on September 1, 1997 in the case of Series S, September 1, 1998 in the case of Series T and September 1, 1999 in the case of Series U; in each case at $100 per share.

Based on an estimated dividend rate at year-end 1993 of 5.25% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (3.25 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $53 million at December 31, 1993.

Note 8. Common Stock

At December 31, 1993, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 36,911,265 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 1,193,613 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 253,090 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

Common Stock

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1991		31,421,268	$516,388
Automatic Dividend Reinvestment and Stock Purchase Plan	$18.750–$23.163	571,669	11,252
Savings Plus Plan	$19.375–$23.563	108,202	2,194
Capital Stock Expense			(495)
Balance, December 31, 1991		32,101,139	$529,339
Sale of Stock	$24.000	2,000,000	48,000
Automatic Dividend Reinvestment and Stock Purchase Plan	$21.325–$24.850	584,854	13,338
Savings Plus Plan	$22.063–$25.188	110,666	2,590
Capital Stock Expense			(1,735)
Balance, December 31, 1992		34,796,659	$591,532
Sale of Stock	$29.625	1,500,000	44,438
Automatic Dividend Reinvestment and Stock Purchase Plan	$25.475–$29.413	515,036	14,076
Savings Plus Plan	$25.813–$29.250	99,570	2,741
Capital Stock Expense			(615)
Balance, December 31, 1993		36,911,265	$652,172

Note 9. Short Term Debt

At December 31, 1993 and December 31, 1992, the Company had short term debt outstanding of $68.1 million and $50.8 million, respectively. The weighted average interest rate on short term debt outstanding at year end 1993 was 3.46% and was 3.48% for borrowings during the year. For 1992, the weighted average interest rate on short term debt outstanding at year end was 3.99% and was 4.28% for borrowings during the year.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years and this agreement has been regularly extended. In November of 1993 the Company was granted a one-year extension of the commitment termination date to December 31, 1996. Commitment fees related to this facility amounted to $1[illegible]9,000 in 1993, $169,000 in 1992 and $149,000 in 1991.

The Company's Charter provides that unsecured debt may not exceed 15 percent of the Company's total capitalization (excluding unsecured debt). As of December 31, 1993, the Company would be able to incur $19.2 million of additional unsecured debt under this provision. In order to be able to use its revolving credit agreement, the Company has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of the Company's Charter.

Since June 1990 the Company has had a credit agreement with a domestic bank providing for up to $20 million of short term debt. Borrowings under this agreement, which has been extended to December 31, 1994, are secured by the Company's accounts receivable.

Also, additional unsecured short term borrowing capacity of up to $70 million is available from domestic banks, at their discretion.

Note 10. Commitments and Other Matters

Capital Expenditures.

The Company's 1994 construction expenditures program is currently estimated at $138 million, including $16 million related to replacement of the steam generators at the Ginna Nuclear Plant and $2 million of Allowance for Funds Used During Construction. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nuclear-Related Matters.

Decommissioning Trust. Under accounting procedures approved by the PSC, the Company has been collecting in its electric rates amounts for the eventual decommissioning of its Ginna Plant and for its 14% share of the decommissioning of Nine Mile Two. The operating licenses for these plants expire in 2009 and 2026, respectively. The Company has collected approximately $61.2 million through December 31, 1993.

The Nuclear Regulatory Commission (NRC) requires reactor licensees to submit funding plans that establish minimum external funding levels for reactor decommissioning. The Company's plan consists principally of an external decommissioning trust fund covering both its Ginna Plant and its Nine Mile Two share. Since 1990, the Company has contributed some $36.9 million to this fund. In addition, the Company maintains an internal reserve to fund the removal of non-radioactive structures, a feature not covered by the NRC minimum funding.

In connection with the Company's rate settlement completed in August 1993, the PSC approved the collection during the rate year ending June 30, 1994 of an aggregate $8.9 million for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $150.7 million for Ginna and $34.3 million for the Company's 14% share of Nine Mile Two (January 1993 dollars). This estimate is based principally on the application of a NRC formula to determine minimum funding. Site-specific studies of the anticipated costs of actual decommissioning are required to be submitted to the NRC at least five years prior to the expiration of the license. The Company intends to fund the external decommissioning trust in the amount of the NRC minimum funding requirement. The difference between the amount to be collected and the NRC minimum will be held in an internal reserve.

The Company is aware of recent NRC activities related to upward revisions to the required minimum funding levels. These activities, primarily focused on disposition of low level radioactive waste, may require the Company to increase funding. The Company continues to monitor these activities but cannot predict what regulatory actions the NRC may ultimately take.

Uranium Enrichment Decontamination and Decommissioning Fund. Nuclear reactor licensees in the U.S. are assessed annually for the decontamination and decommissioning of Department of Energy (DOE) enrichment facilities. The Company made the first of 15 annual payments for this purpose in September 1993, remitting approximately $1.6 million ($1.5 million for the Ginna Plant and $0.1 million for its share of the Nine Mile Two plant). For the two facilities the Company recognized liabilities at December 31, 1993 of $23.4 million ($21.7 million as a long-term liability and $1.7 million as a current liability). In October 1993, the Company began recovery of this deferral through its fuel adjustment clause.

Insurance Program. The Price-Anderson Act establishes a federal program, providing indemnification and insurance against public liability, applicable in the event of a nuclear accident at a licensed U.S. reactor. As a result of amendments to the Act in 1988, the limit of liability has increased to approximately $9.4 billion. Also in 1988 coverage was expanded to include precautionary evacuations and the Act was extended until the year 2002. Under the program, claims would first be met by insurance which licensees are required to carry in the maximum amount available (currently $200 million). If claims exceed that amount, licensees are subject to a retrospective assessment up to $75.5 million per licensed facility for each nuclear incident, payable at a rate not to exceed $10 million per year. Those assessments are subject to periodic inflation-indexing and to a 5% surcharge if funds prove insufficient to pay claims. In addition, the retrospective assessments would be subject to a three percent charge for premium tax. The Company's interests in two nuclear units could thus expose it to a potential liability for each accident of $86.1 million through retrospective assessments of $11.4 million per year in the event of a sufficiently serious nuclear accident at its own or another U.S. commercial nuclear reactor.

Beginning in 1988, coverage for claims alleging radiation-induced injuries to some workers at nuclear reactor sites was removed from the nuclear liability insurance policies purchased by the

Company. Coverage for workers first engaged in nuclear-related employment at a nuclear site prior to 1988 continues to be provided under then-existing nuclear liability insurance policies. Those workers first employed at a nuclear facility in 1988 or later are covered under a separate, industry-wide insurance program. That program contains a retrospective premium assessment feature whereby participants in the program can be assessed to pay incurred losses that exceed the program's reserves. Under the plan as currently established, the Company could be assessed a maximum of $3.1 million over the life of the insurance coverage.

The Company is a member of Nuclear Electric Insurance Limited, which provides insurance coverage for the cost of replacement power during certain prolonged accidental outages of nuclear generating units and coverage for property losses in excess of $500 million at nuclear generating units. As of December 31, 1993, the Company is purchasing a weekly indemnity limit of $3.5 million in the NEIL I replacement power expense program and full policy limits of $1.4 billion in the NEIL II Property Insurance Program for the Ginna Nuclear Power Plant. Coverage under the Property Insurance Program includes the shortfall in the NRC required external trust fund resulting from the premature decommissioning of a nuclear power plant following an accident with property damage in excess of $500 million. The Company currently has designated $166 million as a sublimit for this coverage at the Ginna Nuclear Power Plant. For its share in the generation of Nine Mile Two the Company purchases a weekly indemnity limit of $.5 million in the NEIL I replacement power expense program. The owners at Nine Mile Two purchase the full policy limit of $1.4 billion in the NEIL II Property Insurance Program and the Company pays its proportionate share of those premiums. The owners at Nine Mile Two have selected the maximum available sublimit of $250 million for premature decommissioning. If an insuring program's losses exceeded its other resources available to pay claims, the Company could be subject to maximum assessments in any one policy year of approximately $4.9 million and $14.9 million in the event of losses under the replacement power and property damage coverages, respectively.

Environmental Matters.

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. In recognition of the Company's responsibility to preserve the quality of the air, water, and land it shares with the community it serves, the Company has taken a variety of measures (e.g., self-auditing, recycling and waste minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations and, specifically, to manage and appropriately dispose of wastes currently being generated. The Company, nevertheless, has been contacted, along with numerous others, concerning wastes shipped off-site to licensed treatment, storage and disposal sites where authorities have later questioned the handling of such wastes. In such instances, the Company typically seeks to cooperate with those authorities and with other site users to develop cleanup programs and to fairly allocate the associated costs.

As part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and Remediation (SIR) efforts at Company-owned sites where past waste handling and disposal may have occurred. The Company currently estimates the total costs it could incur for SIR activities at Company-owned sites to be about $20 million. This estimate will vary as better site information is available. The Company anticipates spending $10 million over the next 5 years on SIR initiatives. Approximately $4.5 million has been provided for in rates through June 1996 for recovery of SIR costs. To the extent actual expenditures differ from this amount, they will be deferred for future disposition and recovery as authorized by the PSC.

In 1985, the New York State Department of Environmental Conservation (NYSDEC) identified property in the vicinity of the Lower Falls of the Genesee River (the Lower Falls) in Rochester as an inactive hazardous waste disposal site. The Company owns, and was the prior owner or operator of, a number of locations within the Lower Falls. In mid-1991, NYSDEC advised the Company that it had delisted the Lower Falls site, i.e., removed it from its Registry of Inactive Hazardous Waste Disposal Sites. The effect of delisting is to terminate the Company's status as a potentially responsible party for the Lower Falls site, to discontinue the pending NYSDEC review of a joint Company/City of Rochester proposal for a limited further investigation of the Lower Falls, to defer the prospect of remedial action and perhaps to end any Company sharing of the cost thereof. However, NYSDEC also stated its intention to consider listing individual coal gasification sites within the larger, original site once the State of New York adopts new federal hazardous waste

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criteria. There is at least some material at one of the individual coal gasification sites that could trigger relisting. The Company is unable to predict what further listing action NYSDEC may take, but regards the delisting as a positive development.

The Company and its predecessors formerly owned and operated coal gasification facilities within the Lower Falls. In September 1991 the Company initiated a study of subsurface conditions in the vicinity of retired facilities at its West Station property and has since commenced the removal of soils containing hazardous substances in order to minimize any potential long-term exposure risks. Cleanup efforts have been temporarily suspended while the Company investigates more cost effective remedial technologies. Activities are expected to resume within a year.

On a portion of the Company's property in the Lower Falls, and elsewhere in the general area, the County of Monroe has installed and operates sewer lines. During sewer installation, the County constructed over Company property, pursuant to an easement which the Company granted the County, certain retention ponds which reportedly received from the sewer construction area certain fossil-fuel-based materials ("the materials") found there. In July 1989 the Company received a letter from the County asserting that activities of the Company left the County unable to effect a regulatorily-approved closure of the retention pond area. The County's letter takes the position that it intends to seek reimbursement for its additional costs incurred with respect to the materials once the NYSDEC identifies the generator thereof and that any further cleanup action which the NYSDEC may require at the retention pond site is the Company's responsibility. In the course of discussions over this matter, the County has claimed, without offering any evidence, that the Company was the original generator of the materials. It asserts that it will hold the Company liable for all County costs—presently estimated at $1.5 million—associated both with the materials' excavation, treatment and disposal and with effecting a regulatorily-approved closure of the retention pond area. The Company could incur costs as yet undetermined if it were to be found liable for such closure and materials handling, although provisions of the easement afford the Company rights which may serve to offset all or a portion of any such County claim. To date, the Company has agreed to pay a 20% share of the County's investigation of this area, which commenced in September 1993 and which is estimated to cost no more than $150,000, but no commitment has been made toward any remedial measures which may be recommended by the investigation.

In the letter announcing the delisting of the Lower Falls site, NYSDEC indicated an intention to pursue appropriate closure of the County's former retention pond area, suggesting that it will be evaluated separately to determine whether it meets the criteria of a hazardous waste site. The Company is unable to assess what implications the NYSDEC letter may have for the County's claim against it.

At another location along the River where the Company owns property, a boring taken in Fall 1988 for a sewer system project showed a layer containing a black viscous material. The Company undertook an investigation to determine the extent of the layer. The study found that some of the soil and ground water on-site had been adversely impacted by the hazardous substance constituents of the black viscous material, but evidence was inadequate to determine whether the material or its constituents had migrated off-site. The matter was reported to the NYSDEC and, in September 1990, the Company also provided the agency with a risk assessment for its review. That assessment concluded that the findings warranted no agency action and that site conditions posed no significant threat to the environment. Although NYSDEC could require the Company to undertake further investigation and/or remediation, the agency has taken no action in the nearly three and one-half years since the report's submittal.

In August 1990 the Company was notified of the existence of a federal Superfund site located in Syracuse, NY, known as the Quanta Resources Site. The federal Environmental Protection Agency (EPA) has included the Company in its list of approximately 25 potentially responsible parties (PRPs) at the site, but no data has been produced showing that any of its wastes were delivered to the site. In return for its release from liability for that phase, the Company has joined other PRPs in agreeing to divide among them, utilizing a two-tier structure, EPA's cost of a contractor-performed removal action intended to stabilize the site. The Company, in the lower tier of PRPs, paid its $27,500 share of such cost. The NYSDEC has not yet made an assessment for certain response and investigation costs it has incurred at the site, nor is there as yet any information on which to base an estimate of the cost to design and conduct at the site any remedial measures which federal or state authorities may require.

On May 21, 1993, the Company was notified by NYSDEC that it was considered a potentially responsible party (PRP) for the Frontier Chemical Pendleton Superfund Site located in Pendleton, NY. The Company has signed a PRP Agreement with approximately 15 parties and is participating in negotiations for an Administrative Order on Consent with NYSDEC. The PRPs have negotiated a workplan for site remediation and have retained a consulting firm to implement the workplan. Preliminary estimates indicate site remediation will be between $6 and $8 million. The Company is participating with the group to allocate costs among the PRPs. An allocation scheme has yet to be developed.

Monitoring wells installed at another Company facility in 1989 revealed that an undetermined amount of leaded gasoline had reached the groundwater. The Company has continued to monitor free product levels in the wells, and has begun a modest free product recovery project, reports on both of which are routinely furnished to the NYSDEC. Free product levels in the wells have declined, but authorities may require further remediation once most of the free product has been recovered.

The Company is developing strategies responsive to the Federal Clean Air Act Amendments of 1990 (Amendments). The Amendments will primarily affect air emissions from the Company's fossil-fueled electric generating facilities. The Company is in the process of identifying the optimum mix of control measures that will allow the fossil fuel based portion of the generation system to fully comply with applicable regulatory requirements. Although work is continuing, not all compliance control measures have been determined. The Company has adopted control measures for nitrogen oxides (NOx) emissions which must be in effect by the federally mandated compliance date of May 31, 1995. The chosen NOx control measures consist of the installation of low NOx burners on some units, the derating of unit generation by taking burners out of service on other units and placing one unit on cold standby with the redistribution of load to the remaining more efficient units. Capital costs for NOx controls and the installation of continuous emission monitoring systems are not expected to exceed $6.8 million and will be incurred during 1994 and 1995. A range of capital costs between $20 million and $30 million (1993 dollars) has been estimated for the implementation of several potential scenarios which would enable the Company to meet the foreseeable future NOx and sulphur dioxide requirements of the Amendments. These capital costs would be incurred between 1996 and 2000. The Company currently estimates that it could also incur up to $2 million (1993 dollars) of additional annual operating expenses, excluding fuel, to comply with the Amendments. The use of scrubbing equipment is not presently being considered. Likewise, the purchase or sale of "emission allowances," as allowed by the Amendments, is not currently being considered. The Company anticipates that the costs incurred to comply with the Amendments will be recoverable through rates based on previous rate recovery of environmental costs required by governmental authorities.

Gas Cost Recovery.

Many interstate gas pipeline companies entered into contracts with gas producers which required the pipeline companies to pay for a minimum amount of gas whether or not the gas is actually taken from the producer (take-or-pay costs). Pursuant to FERC authorization, the Company's gas suppliers have included certain amounts of their take-or-pay costs in the rates charged to the Company.

The PSC instituted a proceeding in October 1988 to determine the extent to which the gas distribution companies in New York State would be permitted to recover in rates the take-or-pay costs imposed upon them. Through a series of subsequent settlements between the Staff of the PSC and the Company, the Company was permitted to recover in rates 87.5% of the first $12 million of the pipeline take-or-pay costs imposed upon it and all such costs in excess thereof except for a maximum of $562,500.

As of December 31, 1993 the Company had been billed for $17.6 million of take-or-pay costs and has thus far recovered $16.4 million from its customers. The Company expects only insignificant amounts of take-or-pay costs remain to be billed to the Company.

As a result of the restructuring of the gas transportation industry by the FERC, there will be a number of changes in this aspect of the Company's business over the next several years. These changes, which will apply throughout the industry, will affect different companies differently and may result, at least initially, in increases in the gas transportation costs of the Company. The Company will also be required to pay a share of certain transition costs incurred by the pipelines as a result of the FERC restructuring. Although the final amounts of such transition costs are subject to continuing negotiations with several pipelines and ongoing pipeline filings requiring FERC

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approval, the Company expects such costs to range between \$43.5 and \$52.0 million. A substantial portion of such costs will be on the CNG Transmission Corporation (CNG) system of which approximately \$27 million was billed to the Company on December 3, 1993 payable over the following three years. The Company expects these transition costs to be recoverable in its rates.

In a related matter, in connection with the development of the Empire State Pipeline ("Empire"), the Company is committed as of November 1993, to transportation capacity from Empire, to upstream pipeline transportation and storage service and to the purchase of natural gas in quantities corresponding to these transportation and storage arrangements. The Company also has certain contractual obligations with CNG whereby the Company is subject to demand charges for transportation capacity for a period of eight years. In October 1993, the effective date of implementation of pipeline restructuring pursuant to FERC Order No. 636 and CNG's individual restructuring in Docket No. RS92-14, CNG's transportation rights on upstream pipelines were assigned to its customers, including the Company. The Company has concluded the corresponding contracts with those upstream pipelines.

The transportation service to be provided by Empire was scheduled to phase in over 12 months, at which point the combined CNG and Empire transportation capacity would have exceeded the Company's current requirements. Therefore, the Company recently entered into a marketing agreement with CNG, pursuant to which CNG will assist the Company in obtaining permanent replacement customers for the transportation capacity the Company will not require. It may renegotiate its arrangements with CNG and/or Empire or it may negotiate assignment, on a permanent or temporary basis, of the transportation capacity that exceeds the requirements of its customers. In addition, under FERC rules, the Company may sell its excess transportation capacity in the market. While CNG has already secured letters of intent for a substantial portion of such capacity, whether and to what extent CNG and/or the Company can successfully negotiate the assignment or sale of the excess capacity, or at what price, cannot be determined at the present time. The retention of some or all of this excess transportation capacity may cause an increase in the Company's gas supply costs. This would be in addition to any increase caused by other aspects of the gas transportation restructuring.

Gas Purchase Undercharges.

The Company became aware during 1993 that it did not account properly for certain gas purchases for the period August 1990–August 1992 resulting in undercharges to gas customers of approximately \$7.5 million. The Company had previously estimated the effect to approximate as much as \$10 million; however, further review determined that the magnitude of the error on previously reported operations was substantially less.

The undercharges arose from the increased complexity arising from the federal deregulation of the gas industry and the Company's transition from a full requirements customer of one gas supplier to the purchase of gas transportation service and natural gas on the open market. Problems of this type are routinely corrected through the Gas Adjustment Clause process and appropriate amounts are collected from or refunded to customers. Of the total undercharges, \$2.3 million has previously been expensed and \$5.2 million had been deferred on the Company's balance sheet.

The Company advised the PSC and all parties to the Company's most recent rate proceeding of the undercharges. In its August 24, 1993 Order approving the Company's three-year rate settlement the PSC made the Company's current gas rates temporary solely to consider the impacts of the erroneous gas accounting, and in a September 13, 1993 Order the PSC instituted a proceeding to investigate the resulting undercollections and the recoverability of such amounts from customers. In its September 13 Order the PSC directed the Company to demonstrate fully the existence and amount of the undercharges, to explain the reasons for the errors, and to address possible general and specific legal limitations on the Company's right to recover portions of the undercharges. The Company filed evidence and analysis responsive to that Order on October 27, 1993.

On December 30, 1993, a proposed settlement among the Company, PSC Staff and another party was filed with the PSC. It provides for the recovery in rates of \$3.2 million over three years, subject to audit and to limitations on rate adjustments established in the August 24 Order. The Company wrote off the \$2.0 million balance of the undercharges as of December 31, 1993. That write-off amounts to a reduction in 1993 earnings of four cents per share, net of tax. Although no party, to the Company's knowledge, opposes the proposed settlement, the Company is unable to predict whether the PSC will approve it.

Other Matters.

Regulatory Disallowances. In June 1992 the Company recorded a charge to earnings of $8.2 million in connection with ice storm restoration costs disallowed by the PSC. In December 1991, the Company recorded a non-cash charge against earnings of $10 million for refunds to be made to customers in connection with a PSC fuel procurement audit.

Nuclear Fuel Enrichment Services. The Company has a contract with the United States Enrichment Corporation (USEC), formerly with the DOE, for nuclear fuel enrichment services which assures provision of 70% of the Ginna Nuclear Plant's requirements throughout its service life or 30 years, whichever is less. No payment obligation accrues unless such enrichment services are needed. Annually, the Company is permitted to decline USEC-furnished enrichment for a future year upon giving ten years' notice. Consistent with that provision, the Company has terminated its commitment to USEC for the years 2000, 2001 and 2002. The USEC waived, for an interim period, the obligation to give ten years' notice for 2003. The Company has secured the remaining 30% of its Ginna requirements for the reload years 1994 through 1995 under different arrangements with USEC. The Company plans to meet its enrichment requirements for years beyond those already committed by making further arrangements with USEC or by contracting with third parties. The cost of USEC enrichment services utilized for the next seven reload years (priced at the most current rate) ranges from $4 million to $7 million per year.

Assertion of Tax Liability. The Company's federal income tax returns for 1987 and 1988 have been examined by the Internal Revenue Service (IRS) which has proposed adjustments of approximately $29 million.

The adjustments at issue generally pertain to the characterization and treatment of events and relationships at the Nine Mile Two project and to the appropriate tax treatment of investments made and expenses incurred at the project by the Company and the other co-tenants. A principal issue appears to be the year in which the plant was placed in service.

The Company has filed a protest of the IRS adjustments to its 1987–88 tax liability and has had an initial hearing before the appeals officers. The Company believes it has sound bases for its protest, but cannot predict the outcome thereof. Generally, the Company would expect to receive rate relief to the extent it was unsuccessful in its protest except for that part of the IRS assessment stemming from the Nine Mile Two disallowed costs, although no such assurance can be given.

Report of Independent Accountants

Price Waterhouse

1900 Chase Square
Rochester, New York 14604-1984
January 14, 1994

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation and its subsidiaries at December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993 in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 1 to the financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" in 1993.

Price Waterhouse

Report of Management

The management of Rochester Gas and Electric Corporation has prepared and is responsible for the financial statements and related financial information contained in this Annual Report. Management uses its best judgements and estimates to ensure that the financial statements reflect fairly the financial position, results of operations and cash flows of the Company in accordance with generally accepted accounting principles. Management maintains a system of internal accounting controls over the preparation of its financial statements designed to provide reasonable assurance as to the integrity and reliability of the financial records.

This system of internal control includes documented policies and guidelines and periodic evaluation and testing by the internal audit department.

The Company's financial statements have been examined by Price Waterhouse, independent accountants, in accordance with generally accepted auditing standards. Their examination includes a review of the Company's system of internal accounting control and such tests and other procedures necessary to express an opinion as to whether the Company's financial statements are presented fairly in all material respects in conformity with generally accepted accounting principles. The report of Price Waterhouse is presented on page 53.

The Audit Committee of the Board of Directors is responsible for reviewing and monitoring the Company's financial reporting and accounting practices. The Audit Committee meets regularly with management and the independent accountants to review auditing, internal control and financial reporting matters. The independent accountants have direct access to the Audit Committee, without management present, to discuss the results of their examinations and their opinions on the adequacy of internal accounting controls and the quality of financial reporting.

Management believes that, at December 31, 1993, the Company maintained an effective system of internal control over the preparation of its published financial statements.

Roger W. Kober

Roger W. Kober
Chairman of the Board, President and Chief Executive Officer

Thomas S. Richards
Senior Vice President, Finance and General Counsel

January 22, 1994

Interim Financial Data

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results of operations for such periods. The variations in operations reported on a quarterly basis are a result of the seasonal nature of the Company's business and the availability of surplus electricity.

	(Thousands of Dollars)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings per Common Share (in dollars)
December 31, 1993*	**$256,219**	**$43,756**	**$22,366**	**$20,541**	**$ .55**
September 30, 1993**	**217,278**	**38,058**	**20,204**	**18,379**	**.51**
June 30, 1993	**203,252**	**21,295**	**6,909**	**5,084**	**.15**
March 31, 1993	**272,275**	**44,124**	**29,084**	**27,259**	**.78**
December 31, 1992	$244,290	$41,744	$29,146	$27,073	$ .77
September 30, 1992	198,341	33,006	17,507	15,435	.45
June 30, 1992***	195,154	16,460	(4,579)	(6,651)	(.20)
March 31, 1992	257,747	42,735	28,365	26,293	.81
December 31, 1991****	$229,331	$38,578	$14,911	$12,467	$ .38
September 30, 1991	195,629	31,752	17,262	15,756	.49
June 30, 1991	182,637	17,230	1,538	32	—
March 31, 1991	245,673	37,198	24,286	22,780	.72

*Includes recognition of $1.9 million net-of-tax pension plan curtailment.
**Includes recognition of $3.4 million net-of-tax pension plan curtailment.
***Includes recognition of $5.4 million net-of-tax ice storm disallowance.
****Includes recognition of $6.6 million net-of-tax fuels audit disallowance.

Common Stock and Dividends

Earnings/Dividends	1993	1992	1991
Earnings per weighted average share	**$2.00**	$1.86	$1.60
Dividends paid per share	**$1.72**	$1.68	$1.62

Shares/Shareholders	1993	1992	1991
Number of shares (000's)			
Weighted average	**35,599**	33,258	31,794
Actual number at December 31	**36,911**	34,797	32,101
Number of shareholders at December 31	**38,102**	39,017	39,157

Tax Status of Cash Dividends

Cash dividends paid in 1993, 1992 and 1991 were 100 percent taxable for Federal income tax purposes.

Dividend Policy

The Company has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. The level of future cash dividend payments will be dependent upon the Company's future earnings, its financial requirements and other factors. The Company's Certificate of Incorporation provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company.

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1994, the Company paid a cash dividend of $.44 per share on its Common Stock, up $.01 from the prior quarterly dividend payment of $.43. The January 1994 dividend payment is equivalent to $1.76 on an annual basis.

Common Stock Trading

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

	1993	1992	1991
Common Stock—Price Range			
High			
1st quarter	**28⅜**	23¼	20¾
2nd quarter	**28**	24	20½
3rd quarter	**29¾**	24¾	20⅞
4th quarter	**29¼**	25¼	23⅞
Low			
1st quarter	**24⅛**	20⅞	17¾
2nd quarter	**25½**	21¼	19
3rd quarter	**27⅝**	22¾	19
4th quarter	**24¾**	23⅛	20⅛
At December 31	**26¼**	24½	23¼

Selected Financial Data

(Thousands of Dollars) Year Ended December 31	1993	1992	1991	1990	1989	1988
Consolidated Summary of Operations						
Operating Revenues						
Electric	$638,955	$608,2[illegible]	$588,930	$551,930	$543,096	$514,637
Gas	293,708	261,724	235,728	236,496	264,573	231,217
	932,663	869,991	824,658	788,426	807,669	745,854
Electric sales to other utilities	16,361	25,541	28,612	42,465	38,028	29,966
Total Operating Revenues	949,024	895,532	853,270	830,891	845,697	775,820
Operating Expenses						
Fuel Expenses						
Electric fuels	45,871	48,[illegible]76	65,105	76,420	75,873	65,787
Purchased electricity	31,563	29,706	27,683	34,264	39,645	30,299
Gas purchased for resale	166,884	141,291	129,779	132,512	152,623	129,596
Total Fuel Expenses	244,318	219,373	222,567	243,196	268,141	225,682
Operating Revenues Less Fuel Expenses	704,706	676,159	630,703	587,695	577,556	550,138
Other Operating Expenses						
Operations excluding fuel expenses	235,381	226,624	208,440	194,594	173,764	159,689
Maintenance	61,693	62,720	65,415	62,391	64,316	52,575
Depreciation and Amortization	84,177	85,028	84,181	77,767	75,063	69,703
Taxes—local, state and other	126,892	124,252	113,649	101,035	95,341	88,635
Federal income tax—current	33,453	36,[illegible]01	28,766	20,661	20,509	20,363
—deferred	15,877	7,490	5,493	13,829	17,330	20,299
Total Other Operating Expenses	557,473	542,215	505,944	470,277	446,323	411,264
Operating Income	147,233	133,944	124,759	117,418	131,233	138,874
Other Income and Deductions						
Allowance for other funds used during construction	153	164	675	2,689	2,261	2,047
Federal income tax	9,827	4,195	4,580	2,459	1,439	1,683
Pension plan curtailment	(8,179)	—	—	—	—	—
Regulatory disallowances	(1,953)	(8,215)	(10,000)	—	(2,100)	—
Other, net	(7,074)	6,155	6,078	4,062	8,328	6,901
Total Other Income and (Deductions)	(7,226)	2,299	1,333	9,210	9,928	10,631
Income Before Interest Charges	140,007	136,243	126,092	126,628	141,161	149,505
Interest Charges						
Long term debt	56,451	60,810	63,9[illegible]	64,873	68,628	72,270
Short term debt	1,487	1,950	2,623	1,070	—	—
Other, net	5,220	5,228	4,459	3,523	3,115	2,898
Allowance for borrowed funds used during construction	(1,714)	(2,184)	(2,905)	(2,719)	(2,026)	(1,777)
Total Interest Charges	61,444	65,804	68,095	66,747	69,717	73,391
Net Income	78,563	70,439	57,997	59,881	71,444	76,114
Dividends on Preferred Stock, at Required Rates	7,300	8,290	6,963	6,025	6,025	7,348
Earnings Applicable to Common Stock	$ 71,263	$ 62,149	$ 51,034	$ 53,856	$ 65,419	$ 68,766
Weighted Average Number of Shares Outstanding in Each Period (000's)	35,599	33,258	31,794	31,293	31,090	30,513
Earnings per Common Share	$2.00	$1.86	$1.60	$1.72	$2.10	$2.25
Cash Dividends Paid per Common Share	$1.72	$1.68	$1.62	$1.56	$1.50	$1.50

Condensed Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1993	1992	1991	1990	1989	1988
Assets						
Utility Plant	**$2,890,799**	$2,798,581	$2,706,554	$2,310,294	$2,208,158	$2,122,922
Less: Accumulated depreciation and amortization	**1,335,083**	1,253,117	1,178,649	812,994	730,621	653,876
	1,555,716	1,545,464	1,527,905	1,497,300	1,477,537	1,469,046
Construction work in progress	**112,750**	83,834	76,848	82,663	68,784	41,044
Net utility plant	**1,668,466**	1,629,298	1,604,753	1,579,963	1,546,321	1,510,090
Current Assets	**248,589**	209,621	189,009	176,045	190,321	213,626
Investment in Empire	**38,560**	9,846	—	—	—	—
Deferred Debits	**502,015**	200,676	160,034	108,451	102,729	102,015
Total Assets	**$2,457,630**	$2,049,441	$1,953,796	$1,864,459	$1,839,371	$1,825,731
Capitalization and Liabilities						
Capitalization						
Long term debt	**$ 747,631**	$ 658,880	$ 672,322	$ 721,612	$ 764,627	$ 792,976
Preferred stock redeemable at option of Company	**67,000**	67,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	**42,000**	54,000	60,000	30,000	30,000	30,000
Common shareholders' equity						
Common stock	**652,172**	591,532	529,339	516,388	513,560	504,907
Retained earnings	**75,126**	66,968	61,515	62,542	57,983	39,710
Total common shareholders' equity	**727,298**	658,500	590,854	578,930	571,543	544,617
Total Capitalization	**1,583,929**	1,438,380	1,390,176	1,397,542	1,433,170	1,434,593
Long Term Liabilities (Department of Energy)	**89,804**	94,602	63,626	59,989	55,502	51,016
Current Liabilities	**234,530**	267,276	267,601	183,720	137,899	126,661
Deferred Credits and Other Liabilities	**549,367**	249,183	232,393	223,208	212,800	213,461
Total Capitalization and Liabilities	**$2,457,630**	$2,049,441	$1,953,796	$1,864,459	$1,839,371	$1,825,731

Financial Data

At December 31	1993	1992	1991	1990	1989	1988
Capitalization Ratios (a) (percent)						
Long term debt	**49.4**	48.2	50.6	53.6	55.1	56.8
Preferred stock	**6.6**	8.0	8.7	6.7	6.5	6.5
Common shareholders' equity	**44.0**	43.8	40.7	39.7	38.4	36.7
Total	**100.0**	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	**$19.70**	$18.92	$18.41	$18.42	$18.28	$17.69
Rate of Return on Average Common Equity (percent)	**10.25**	9.98	8.60	9.29	11.56(b)	12.68
Embedded Cost of Senior Capital (percent)						
Long term debt	**7.36**	7.91	8.32	8.59	8.74	8.71
Preferred stock	**6.69**	6.98	6.97	6.72	6.72	6.72
Effective Federal Income Tax Rate (percent)	**33.5**	35.9	33.9	34.8	33.8	33.9
Depreciation Rate (percent)—Electric	**2.62**	2.69	3.05	3.33	3.25	3.56
—Gas	**2.60**	2.78	2.94	2.94	2.96	2.96
Interest Coverages (b)(c)						
Before federal income taxes (incld. AFUDC)	**3.03**	2.74	2.38	2.32	2.53	2.53
(excld. AFUDC)	**3.00**	2.70	2.33	2.25	2.47	2.48
After federal income taxes (incld. AFUDC)	**2.35**	2.12	1.91	1.86	2.02	2.01
(excld. AFUDC)	**2.32**	2.08	1.86	1.78	1.96	1.96

(a) Includes Company's long term liability to the Department of Energy (DOE) for nuclear waste disposal. Excludes DOE long term liability for uranium enrichment decommissioning and amounts due or redeemable within one year.

(b) Excludes disallowed Nine Mile Two plant costs written off in 1989.

(c) The recognition by the Company in 1991 of a fuel procurement audit approved by the New York State Public Service Commission (PSC) has been excluded from 1991 coverages. Likewise, recognition by the Company in 1992 of disallowed ice storm costs as approved by the PSC has been excluded from 1992 coverages. Coverages for 1993 exclude the effects of retirement enhancement programs recognized by the Company during the year and certain gas purchase undercharges written off in December 1993.

Electric Department Statistics

Year Ended December 31	1993	1992	1991	1990	1989	1988
Electric Revenue (000's)						
Residential	$235,286	$220,866	$212,327	$197,612	$191,732	$188,451
Commercial	196,456	184,815	181,561	165,445	155,076	149,663
Industrial	147,396	142,392	141,001	130,012	124,634	120,490
Other (Includes Unbilled Revenue)	59,817	60,194	54,041	58,861	71,654	56,033
Electric revenue from our customers	638,955	608,267	588,930	551,930	543,096	514,637
Other electric utilities	16,361	25,541	28,612	42,465	38,028	29,966
Total electric revenue	655,316	633,808	617,542	594,395	581,124	544,603
Electric Expense (000's)						
Fuel used in electric generation	45,871	48,376	65,105	76,420	75,873	65,787
Purchased electricity	31,563	29,706	27,683	34,264	39,645	30,299
Other operation	188,684	183,118	168,610	155,289	137,458	124,871
Maintenance	52,464	53,714	57,032	53,880	55,915	44,060
Depreciation and Amortization	72,326	73,213	72,746	67,302	65,287	60,444
Taxes—local, state and other	96,043	94,841	86,925	77,323	71,361	66,426
Total electric expense	486,951	482,968	478,101	464,478	445,539	391,887
Operating Income before Federal Income Tax	168,365	150,840	139,441	129,917	135,585	152,716
Federal income tax	43,845	38,046	31,390	30,670	29,887	34,093
Operating Income from Electric Operations (000's)	$124,520	$112,794	$108,051	$ 99,247	$105,698	$118,623
Electric Operating Ratio %	48.6	49.7	51.6	53.8	53.2	48.7
Electric Sales—KWH (000's)						
Residential	2,124,763	2,084,466	2,085,429	2,075,072	2,072,047	2,051,808
Commercial	1,987,490	1,937,950	1,928,730	1,897,583	1,832,521	1,792,162
Industrial	1,894,026	1,929,498	1,917,796	1,931,633	1,906,429	1,869,417
Other	505,341	503,330	507,765	490,077	491,905	483,730
Total billed	6,511,620	6,455,244	6,439,720	6,394,365	6,302,902	6,197,117
Unbilled sales	(4,556)	742	7,657	(25,421)	33,406	—
Total customer sales	6,507,064	6,455,986	6,447,377	6,368,944	6,336,308	6,197,117
Other electric utilities	743,588	1,062,738	1,034,370	1,316,379	1,255,282	1,149,900
Total electric sales	7,250,652	7,518,724	7,481,747	7,685,323	7,591,590	7,347,017
Electric Customers at December 31						
Residential	302,219	300,344	298,440	296,110	293,418	290,037
Commercial	29,635	29,339	28,856	28,804	28,386	27,888
Industrial	1,382	1,386	1,388	1,428	1,422	1,392
Other	2,638	2,605	2,558	2,553	2,512	2,326
Total electric customers	335,874	333,674	331,242	328,895	325,738	321,643
Electricity Generated and Purchased—KWH (000's)						
Fossil	1,520,936	2,197,757	2,146,664	2,505,110	2,578,006	2,214,588
Nuclear	4,495,457	4,191,035	4,391,480	4,016,721	3,659,185	3,884,884
Hydro	199,239	278,318	174,239	244,539	175,085	169,002
Pumped storage	233,477	226,391	240,206	269,966	290,582	292,305
Less energy for pumping	(355,725)	(344,245)	(364,520)	(405,966)	(429,895)	(430,401)
Other	2,559	811	1,269	20,408	54,893	2,195
Total generated—Net	6,095,943	6,550,067	6,589,338	6,650,778	6,327,856	6,132,573
Purchased	1,583,582	1,389,875	1,451,208	1,498,089	1,757,413	1,705,755
Total electric energy	7,679,525	7,939,942	8,040,546	8,148,867	8,085,269	7,838,328
System Net Capability—KW at December 31						
Fossil	541,000	541,000	541,000	541,000	541,000	541,000
Nuclear	620,000	617,000	622,000	621,000	621,000	621,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	29,000	29,000	29,000	29,000	29,000	29,000
Purchased	347,000	348,000	354,000	356,000	369,000	360,000
Total system net capability	1,584,000	1,582,000	1,593,000	1,594,000	1,607,000	1,598,000
Net Peak Load—KW	1,333,000	1,252,000	1,297,000	1,208,000	1,249,000	1,275,000
Annual Load Factor—Net %	59.1	62.5	61.7	64.6	62.4	59.7

Gas Department Statistics

Year Ended December 31	1993	1992	1991	1990	1989	1988
Gas Revenue (000's)						
Residential	**$ 5,526**	$ 6,456	$ 6,354	$ 6,508	$ 6,770	$ 6,439
Residential spaceheating	**196,411**	185,405	157,458	159,501	165,832	150,383
Commercial	**45,620**	44,274	40,196	43,534	46,897	44,781
Industrial	**6,346**	6,418	6,761	9,674	9,371	9,859
Municipal and other (Includes Unbilled Revenue)	**39,805**	21,171	24,959	17,279	35,703	19,755
Total gas revenue	**293,708**	261,724	235,728	236,496	264,573	231,217
Gas Expense (000's)						
Gas purchased for resale	**166,884**	141,291	129,779	132,512	152,623	129,596
Other operation	**46,697**	43,506	39,830	39,307	36,306	34,818
Maintenance	**9,229**	9,006	8,383	8,510	8,401	8,515
Depreciation	**11,851**	11,815	11,435	10,465	9,776	9,259
Taxes—local, state and other	**30,849**	29,411	26,724	23,711	23,980	22,209
Total gas expense	**265,510**	235,029	216,151	214,505	231,086	204,397
Operating Income before Federal Income Tax	**28,198**	26,695	19,577	21,991	33,487	26,820
Federal income tax	**5,485**	5,545	2,869	3,820	7,952	6,569
Operating Income from Gas Operations (000's)	**$ 22,713**	$ 21,150	$ 16,708	$ 18,171	$ 25,535	$ 20,251
Gas Operating Ratio %	**75.9**	74.1	75.5	76.3	74.6	74.8
Gas Sales—Therms (000's)						
Residential	**6,735**	8,780	9,068	9,644	10,321	10,374
Residential spaceheating	**289,252**	287,614	253,655	262,458	277,267	267,697
Commercial	**77,326**	78,993	71,509	77,617	84,152	86,413
Industrial	**11,792**	12,437	13,000	18,536	17,873	20,174
Municipal	**11,947**	11,410	10,580	13,350	12,319	15,514
Total billed	**397,052**	399,234	357,812	381,605	401,932	400,172
Unbilled sales	**8,017**	13	3,291	(22,840)	20,320	—
Total gas sales	**405,069**	399,247	361,103	358,765	422,252	400,172
Transportation of customer-owned gas	**124,436**	126,140	109,835	101,985	105,303	83,594
Total gas sold and transported	**529,505**	525,387	470,938	460,750	527,555	483,766
Gas Customers at December 31						
Residential	**18,389**	19,114	21,448	22,410	23,321	24,139
Residential spaceheating	**231,937**	228,096	222,918	219,242	215,120	210,710
Commercial	**18,636**	18,378	18,151	17,920	17,677	17,213
Industrial	**924**	932	921	960	1,095	1,042
Municipal	**1,001**	1,010	983	984	1,067	1,039
Transportation	**466**	424	423	401	367	270
Total gas customers	**271,353**	267,954	264,844	261,917	258,647	254,413
Gas—Therms (000's)						
Purchased for resale	**347,778**	360,493	384,643	366,684	426,941	408,044
Gas from storage	**76,378**	53,757	16,755	—	—	—
Other	**1,039**	1,061	1,617	2,525	1,764	1,967
Total gas available	**425,195**	415,311	403,015	369,209	428,705	410,011
Cost of gas per therm (cents)	**35.79¢**	35.35¢	32.96¢	36.03¢	35.74¢	31.76¢
Total Daily Capacity—Therms at December 31*	**4,485,000**	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000
Maximum daily throughput—Therms	**3,864,850**	3,768,470	3,539,260	3,539,820	3,719,050	3,744,500
Degree Days (Calendar Month)						
For the period	**7,044**	6,981	6,146	5,924	7,109	6,862
Percent colder (warmer) than normal	**4.4**	3.4	(8.4)	(11.8)	5.9	1.6

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

Investor Information

Requests for Information
Investors and security analysts seeking information about the Company should contact David C. Heiligman, Vice President, Secretary and Treasurer.

Form 10-K Annual Report
Shareholders may obtain a copy of the Company's 1993 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by writing to the Secretary.

Shareholder Services
Shareholders with questions about dividend payments, address changes, missing certificates, ownership changes and other account information should contact our transfer agent.

Dividend Payment Dates
RG&E's Board of Directors meets quarterly to consider the payment of dividends. Dividends on Common Stock are normally paid on or about the 25th of January, April, July and October. Dividends on the Preferred Stocks are payable, as declared, on or about the 1st of March, June, September and December.

Dividend Direct Deposit
Shareholders can elect to have their quarterly cash dividends electronically deposited into their personal bank accounts. Deposits are made on the date the dividend is payable. If you would like to take advantage of this service, contact our transfer agent.

Dividend Reinvestment
Common Stock shareholders who wish to acquire additional shares free of brokerage commissions or service charges are invited to join RG&E's Automatic Dividend Reinvestment and Stock Purchase Plan. Under the plan, shareholders authorize an independent agent to purchase shares of RG&E Common Stock with their cash dividends. Shareholders may also participate in the plan by making optional cash payments, even if they decide not to reinvest their dividends. For further information, contact our transfer agent.

Duplicate Mailings
Shareholders with more than one account generally receive duplicate mailings of annual and other reports. To eliminate additional mailings, write to our transfer agent. Enclose labels or label information, where possible. Separate dividend checks and proxy material will continue to be sent for each account of record.

Stock Listings
RG&E's Common Stock is listed on the New York Stock Exchange and is identified by the stock symbol RGS. The Preferred Stock issues are traded on the over-the-counter market.

Corporate Office
Rochester Gas and
Electric Corporation
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Rochester, NY 14649-0001
(716) 546-2700

Agent for Automatic Dividend Reinvestment and Stock Purchase Plan
The First National Bank of Boston
Dividend Reinvestment Unit
Mail Stop: 45-01-06
P.O. Box 1681
Boston, MA 02105-1681
(800) 442-2001

Transfer Agent and Registrar
The First National Bank of Boston
Shareholder Services Division
Mail Stop: 45-02-09
P.O. Box 644
Boston, MA 02102-0644
(800) 442-2001

First Mortgage Bond Trustee and Paying Agent
Bankers Trust Company
Attn: Security Holder Relations
P.O. Box 9006
Church Street Station
New York, NY 10249
(800) 735-7777

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Officers
(as of January 1, 1994)

Roger W. Kober
Chairman of the Board, President and Chief Executive Officer
Age 60, Years of Service, 28

David K. Laniak
Senior Vice President, Gas, Electric Distribution and Customer Services
Age 58, Years of Service, 39

Thomas S. Richards
Senior Vice President, Finance and General Counsel
Age 50, Years of Service, 2

Robert E. Smith
Senior Vice President, Production and Engineering
Age 56, Years of Service, 34

David C. Heiligman
Vice President, Secretary and Treasurer
Age 53, Years of Service, 30

Robert C. Mecredy
Vice President, Ginna Nuclear Production
Age 48, Years of Service, 22

Wilfred J. Schrouder, Jr.
Vice President, Employee Relations, Public Affairs and Materials Management
Age 52, Years of Service, 31

Daniel J. Baier
Assistant Controller
Age 47, Years of Service, 10

John M. Kuebel
Auditor
Age 58, Years of Service, 29

Officer Appointment

In October 1993, Thomas S. Richards was elected Senior Vice President, Finance and General Counsel. Mr. Richards had previously been General Counsel of the Company.

Board of Directors
(as of January 1, 1994)

William Balderston III *‡√
Former Executive Vice President,
The Chase Manhattan Corporation

Angelo J. Chiarella †
President and Chief Executive Officer,
Midtown Holdings Corp.

Allan E. Dugan *†
Senior Vice President,
Corporate Strategic Services,
Xerox Corporation

William F. Fowble †‡
Former Senior Vice President and
Executive Vice President, Imaging,
Eastman Kodak Company

Jay T. Holmes √
Senior Vice President–Corporate
Affairs and Secretary,
Bausch & Lomb Incorporated

Roger W. Kober *
Chairman of the Board, President
and Chief Executive Officer,
Rochester Gas and Electric Corporation

Theodore L. Levinson †
Former President and
Chief Executive Officer,
Star Supermarkets, Inc.

Constance M. Mitchell †√
Former Program Director,
Industrial Management Council of
Rochester, New York, Inc.

Cornelius J. Murphy *‡
Senior Vice President,
Goodrich & Sherwood Company

Arthur M. Richardson *‡√
President,
Richardson Capital Corporation

M. Richard Rose †‡
Former President,
Rochester Institute of Technology

Harry G. Saddock *√
Former Chairman of the Board and
Chief Executive Officer,
Rochester Gas and Electric Corporation

* Member of Executive and Finance Committee
† Member of Audit Committee
‡ Member of Committee on Management
√ Member of Nominating Committee

Class II—Term Expiring in 1994, from left,
M. Richard Rose, Theodore L. Levinson,
Arthur M. Richardson, Allan E. Dugan.

Class III—Term Expiring in 1995, from left,
Cornelius J. Murphy, Angelo J. Chiarella,
Harry G. Saddock, Jay T. Holmes.

Class I—Term Expiring in 1996, from left,
Roger W. Kober, William Balderston III,
William F. Fowble, Constance M. Mitchell.

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Rochester Gas and Electric Corporation
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