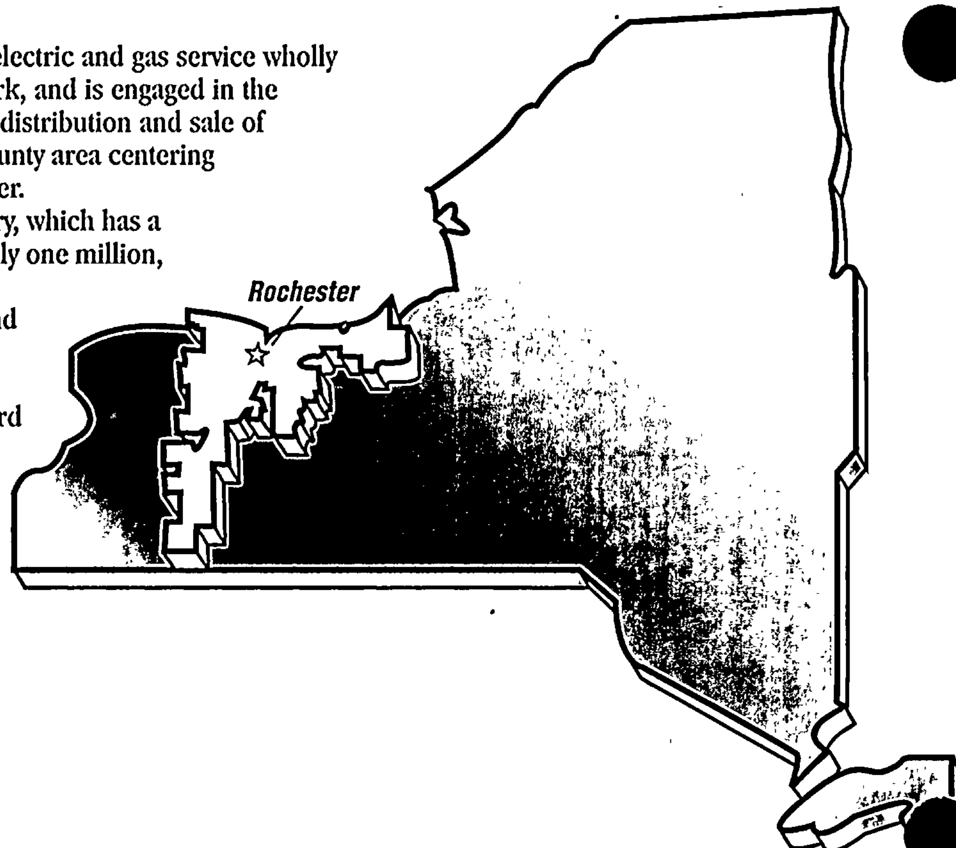

RG&E – THE POWER TO BE THE BEST
THE WORLD'S IMAGE CENTRE
ROCHESTER, N.Y.

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 substantial suburban area with commercial growth and a large prosperous farming area.



FRONT COVER

Rochester is a community where visionary companies flourish.

Just ask Eastman Kodak, Xerox, Bausch & Lomb, or a host of other smaller firms that have built world-wide reputations in imaging and other vital technologies.

As a matter of fact, Rochester is such a great place to grow that over 133 companies in high technology, imaging and optics have located here, earning Rochester recognition as the world's imaging centre. A highly skilled workforce supplies a steady pool of competitive talent.

Rochester Gas and Electric Corporation has a long record of supporting the ambitions of companies that call Rochester home. We offer highly competitive rates and a sure, steady power supply to meet our customers' needs. In short, RG&E is ready to do whatever it takes to bring new business to Rochester and to help it flourish once it's here.

RG&E wishes to acknowledge the following companies and individuals for assistance with the cover images: Xerox Corporation, Rochester Photonics Corporation and Greater Rochester Visitors Association. Photography: Donald Cobb, Alex Shukoff, Lori Farr and Douglas Manchee. Digital Imaging: Attenzione Graphics.

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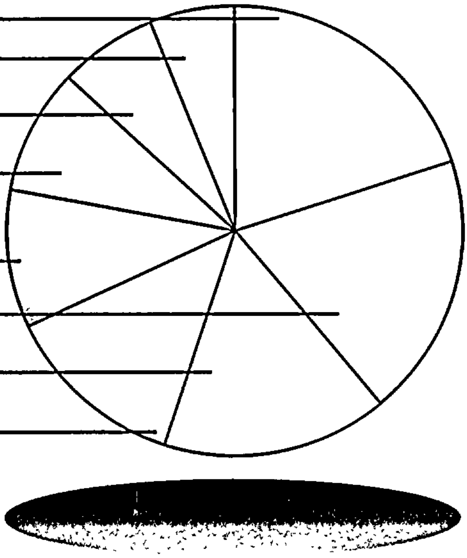
1995 REVENUE DOLLAR

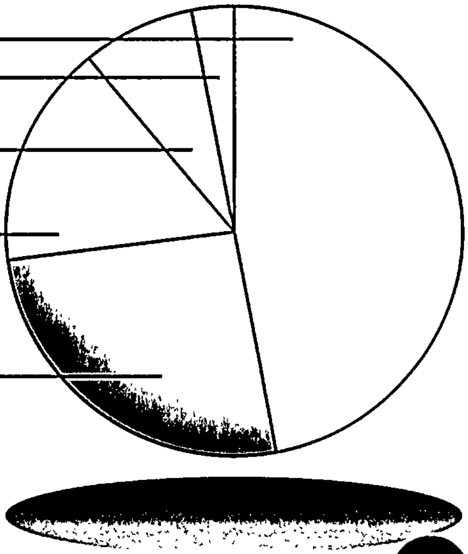
Use of 1995 Revenue Dollar

Other Operations	20¢
Interest	6¢
Dividends & Reinvested Earnings	7¢
Depreciation & Amortization	9¢
Electric Fuel & Purchased Electricity	10¢
Taxes	20¢
Purchased Gas	16¢
Wages & Benefits	12¢



Source of 1995 Revenue Dollar

Residential (25¢ Electric, 22¢ Gas)	47¢
Electric Sales to Other Utilities	3¢
Other (7¢ Electric, 1¢ Gas)	8¢
Industrial (15¢ Electric, 1¢ Gas)	16¢
Commercial (21¢ Electric, 5¢ Gas)	26¢



Financial Highlights

	1995	1994	% Change
Financial Data (Dollars in Thousands)			
Operating revenues: Electric	$722,465	$674,753	7
Gas	$293,863	$326,061	(10)
Operating expenses	$860,955	$845,802	2
Operating income	$155,373	$155,012	—
Net income	$ 71,928	$ 74,375	(3)
Earnings applicable to common stock	$ 64,463	$ 67,006	(4)
Rate of return on average common equity:			
As reported	8.37%	8.92%	(6)
Before non-recurring items	12.10%	11.90%	2
Common Stock Data			
Weighted average number of shares outstanding (thousands)	38,113	37,327	2
Per common share:			
Earnings as Reported	$1.69	$1.79	(6)
Earnings before non-recurring items	$2.44	$2.39	2
Dividends	$1.80	$1.76	2
Book Value (year end)	$19.71	$19.78	—
Year-end market price	$22.63	$20.88	8
Number of Common Stock Shareholders at December 31	35,356	37,212	(5)
Operating Data			
Sales (thousands)			
Kilowatt-hours to customers	6,705,817	6,520,287	3
Kilowatt-hours to other utilities	1,484,196	1,021,733	45
Therms of gas sold and transported	520,238	520,006	—
Customers (year end)			
Electric	341,085	338,509	1
Gas	277,203	274,342	1
Construction expenditures, less allowance for funds used during construction (thousands)	$109,547	$117,219	(7)
Employees (year end)	2,046	2,075	(1)

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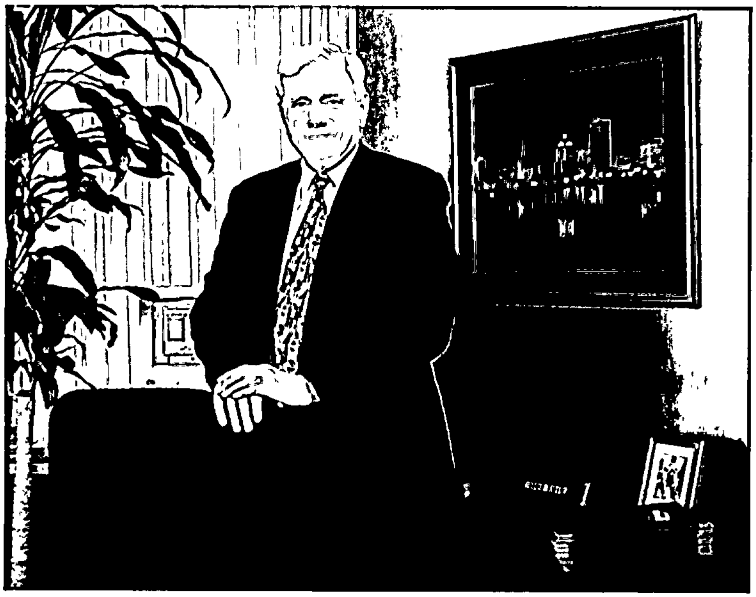
Shareholder's Letter



Roger W. Kober

We are making progress with our plans which are moving us well along in the transition to competition. Our employees are continuing to be highly productive and are holding the line on operating costs. We remain successful holding on to all of our major commercial and industrial customers, and we're the only investor owned energy company in New York State still able to make that claim.

Our corporate business plan is meeting with success. It is constantly updated and enhanced as new opportunities arise in the emerging competitive environment. We permanently filled the chief financial officer position with an executive from outside the industry who joins us in the capacity of a senior vice president.

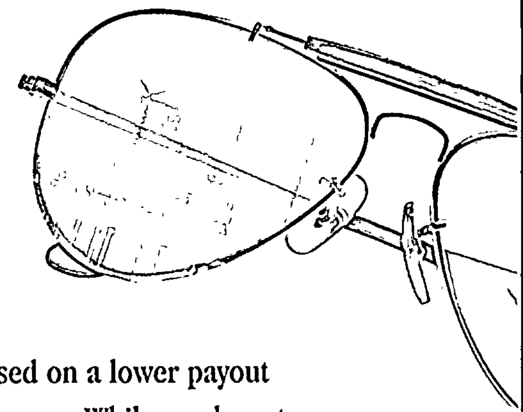
The growing pace of competition in the energy industry continues to be the primary focus of management. We accept the challenges of this new environment and are working to anticipate not only the impact on your company but the opportunities that this new world will present.

In the Spring of 1995 we set a new strategic direction for the future. Highlights of that strategy include:

- The intention to focus on the retail energy services business
- Our goal of market leadership in that business.
- Achieving that goal through operational excellence.

Our core business will be marketing and providing electricity, natural gas, transmission and distribution services, as well as other energy-related services to retail customers. A closely aligned business will be providing gas transmission, and gas and electric distribution services to other energy services companies. We are continuously assessing strategies that may enhance our ability to respond to competitive forces and regulatory change. These strategies are assessed in an effort to provide the greatest possible long-term value to you, our shareholders, giving consideration to changing economic, regulatory and political circumstances.

SHAREHOLDER'S LETTER



Our decision to not increase the dividend last December reflects our belief that our dividend payments need to be evaluated in the context of maintaining the financial strength necessary to operate in this more competitive and uncertain business environment.

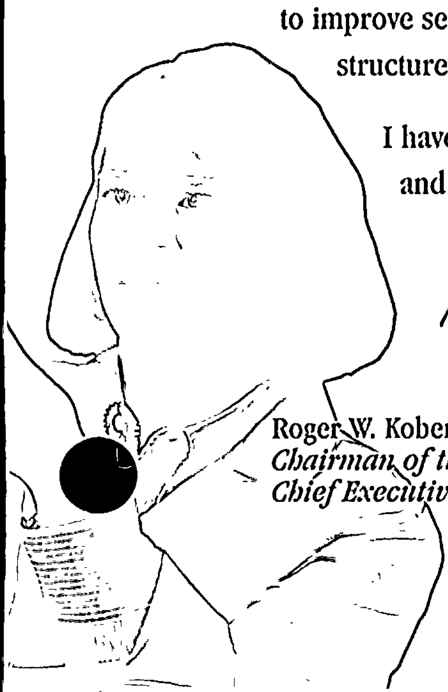
As we move forward, future dividend decisions will need to be based on a lower payout ratio; reevaluating assets and managing greater fluctuations in revenue. While we do not expect these factors to affect our ability to pay dividends at the current rate, future dividends may be affected.

Our local economy is looking good and is very promising for the future. Local business and industrial giants such as Eastman Kodak Company, Xerox and Bausch & Lomb are restructuring and rebuilding. The Greater Rochester Area is billed as the Image Centre of the World. The refocusing of the industrial product base, along with continued innovation in the imaging sciences and products, point to a resurgence of what is the last major manufacturing base in New York State. It points to a future where energy, energy quality, reliability and service will play an increasingly important role. We're ready for it.

We plan to make it so that customers don't think of electricity and gas as just commodities. To succeed and grow we have to make them think of our energy as the best brand, and the brand is RG&E. We're working along those lines.

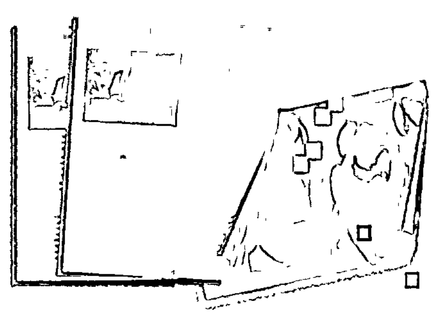
Our 1996 long-range corporate business plan restates that vision. We will be the market leader in bringing people a higher quality of life through the use of energy. With the vision is the mission: that is to market and provide energy and energy-related services to people in their homes and businesses, with 100% satisfaction, 100% of the time. Our major focus is to improve service quality, stabilize prices, improve employee performance, reduce our cost structure and, through these, grow the business.

I have great confidence in our future and in your investment in Rochester Gas and Electric Corporation.



Roger W. Kober

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



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

Earnings Summary

A good summer cooling season, a modest increase in electric rates, and savings from prior years' work force reduction programs, together with other cost control efforts by the Company helped to boost operating earnings for 1995.

Presented below is a table which summarizes the Company's Common Stock earnings on a per-share basis. Earnings per share, before non-recurring items, were $2.44 in 1995. Non-recurring items and their effect on earnings per share have been identified. Earnings per share as reported in 1995 were reduced by an aggregate pretax amount of $44.2 million, or $.75 per share net-of-tax, in connection with a negotiated settlement (see 1995 Gas Settlement) reached between the Company, Staff of the New York State Public Service Commission (PSC) and other parties resolving various proceedings to review issues affecting the Company's gas costs.

Future earnings will be affected, in part, by the Company's ability to control certain costs and its ability to remarket excess gas capacity as set under the terms of the 1995 Gas Settlement, which is discussed under Rates and Regulatory Matters.

The final outcome of a rate proposal submitted by the Company and currently pending before the PSC as well as the impact of developing competition in the energy marketplace are anticipated to affect future earnings.

To provide for increases in past due accounts, an additional expense accrual for doubtful accounts was recognized by the Company in 1995, reducing 1995 pretax earnings by $15.0 million, or $.26 per share.

Earnings per share as reported in 1994 and 1993 reflect charges for work force reduction programs completed in 1994. By the end of 1994, a total of 572 persons, or about 22 percent of the work force, elected to participate in one of three programs which were offered. The overall after-tax savings of these programs are estimated to be about $61 million through 1998. In addition to the cost of the work force reduction programs, earnings as reported include a charge of $.01 per share in 1994 and $.04 per share in 1993 for purchased gas undercharges (see Rates and Regulatory Matters).

Earnings per Share—Summary

(Dollars per Share)	1995	1994	1993
Earnings per Share Before Non-recurring Items	$2.44	$2.39	$2.19
Non-recurring Items			
1995 Gas Cost Settlement	(.75)		
Purchased Gas Undercharges		(.01)	(.04)
Retirement Enhancement Programs		(.59)	(.15)
Total Non-recurring Items	$ (.75)	$ (.60)	$ (.19)
Reported Earnings per Share	$1.69	$1.79	$2.00

Competition

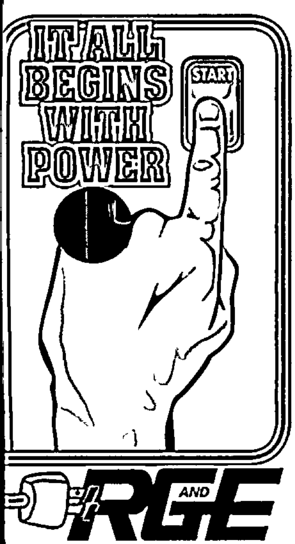
Overview. The Company is operating in a rapidly changing competitive marketplace for electric and gas service. In its electric business, this competitive environment includes a federal and State trend toward deregulation. The passage of the National Energy Policy Act of 1992 (Energy Act) encourages competition in the electric power industry at the wholesale level and promotes access to utility-owned transmission facilities upon payment of appropriate prices. At the State level, the PSC is currently investigating the establishment of an efficient wholesale electric competitive market, and various issues relating to retail electric service competition.

Competition in the Company's gas business was accelerated with the passage in April 1992 of the Federal Energy Regulatory Commission's (FERC) Order No. 636. In essence, FERC Order 636 requires interstate natural gas pipeline companies to offer customers "unbundled", or separately-priced, sale and transportation services.

Electric Utility Competition. Cost pressures on major customers, excess electric capacity in the region, and new technology have created incentives for customers to investigate different electric supply options. Those options have included 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.

PSC Competitive Opportunities Case

Phase I of a PSC proceeding to address various issues related to increasing competition in the New York State electric energy markets (the Competitive Opportunities Case) was completed in the summer of 1994. The PSC approved flexible rate discounts for non-residential electric customers who have competitive alternatives and adopted specific guidelines for such rates.



Under Phase II of the Competitive Opportunities Case, the PSC issued an Opinion in June 1995 establishing nine principles to guide the transition to competition in the electric industry. Among other things, the PSC endorsed increased emphasis on market-based approaches to research, environmental protections and energy efficiency, and it supported the concept that utilities should have a reasonable opportunity to recover expenditures and commitments made pursuant to historical obligations. The PSC also indicated that the current vertically integrated industry structure must be thoroughly examined to ensure that it does not impede effective wholesale or retail competition. In October 1995, formal submissions were made in support of, or opposition to, the various proposals being considered for restructuring the electric industry in New York State. The majority of submissions supported the concept that competition should extend to the level of individual retail customers. The Staff of the PSC endorsed the idea that existing utility companies should be required to separate generation from transmission and distribution facilities (including the possible divestiture of generating assets) to foster greater competition. The PSC Staff position also encouraged electric wholesale competition by 1997, retail competition by 1998, and stated that the New York investor-owned utilities should absorb a portion of any stranded investment. The Company does not support the PSC Staff position, but does agree with the spirit underlying the PSC's guiding principles as presented in June 1995. As discussed below, in October 1995 the Company, along with other New York utilities, presented a consensus position to the PSC under Phase II of the Competitive Opportunities Case through the Energy Association of New York State (the Energy Association), an electric utility industry association which is representing the Company and other utilities in the Competitive Opportunities Case.

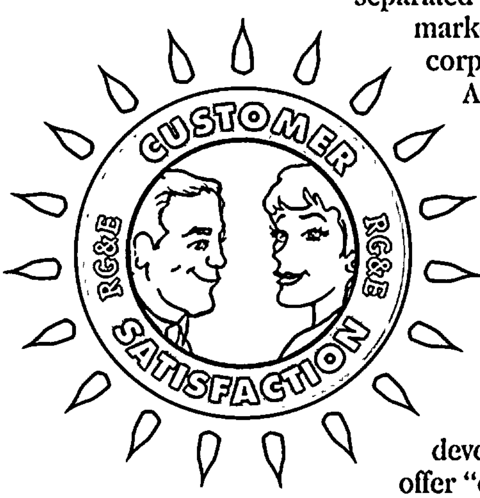
In summary, the Energy Association endorses the following:

- the creation of a pool market mechanism through which all electricity producers would compete,
- creation of an independent system operator to coordinate bulk power transmission and the pool market mechanism,
- regulatory and tax reform that would reduce taxes paid by utilities and limit any increases in the price of electricity and,
- creation of a mechanism for generators to recover investments made pursuant to legal obligations to provide universal service.

The Energy Association stopped short of endorsing increased competition at the retail level, citing several unresolved issues created by different obligations to serve customers when more than one supplier is selling energy in a single area. The Company cannot predict if this proposal will be adopted by the PSC in its Competitive Opportunities Case or its effect on the Company because potential business risks faced by the Company will depend on the specific details of any plan ultimately adopted by the PSC.

On December 21, 1995 a Recommended Decision was issued by the Administrative Law Judge presiding over this proceeding. In summary, it provides:

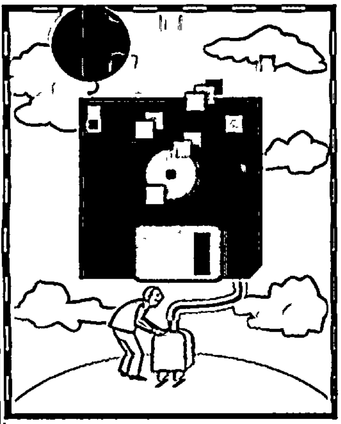
- Competition in the generation or production section of the electric industry should be pursued, as long as steps are taken to ensure that unregulated monopoly does not result and that reliability is not impaired. A preferred competitive model, which includes, among other things, the establishment of an independent system operator to perform a variety of essential functions to ensure the reliable operation of the system was presented.
- Retail competition has the potential to benefit all customers by providing greater choice among their electricity providers as well as increased pricing and reliability options. But retail access brings with it significant risks and requires considerable caution, and should be provided only if it is in the best interests of all consumers.
- In order to ensure reliability, effective competition at the wholesale level should be established first, with an eye toward adding retail access as rapidly as possible once a market is established and reliability is ensured.
- Strandable costs must be determined to be prudent, verifiable, and incapable of being reduced before recovery is allowed. Recovery of strandable costs generally should be accomplished by a non-bypassable access charge or wires charge imposed by the distribution company. There must also be a "reasonable opportunity" for consumers to realize savings and receive reasonable prices. This requires a careful balancing of interests and expectations, and the level of recovery may vary utility by utility.
- In any model under which the production of electricity is deregulated, this function must be separated from transmission and distribution systems in order to limit the exercise of market power. Utilities should make individual proposals regarding preferable corporate structures, explaining how market power will be alleviated.



A final ruling by the PSC on Phase II of the Competitive Opportunities Case is expected in the Spring of 1996. The Company is not able to predict what policies or guidelines may ultimately be adopted by the PSC under this proceeding. The nature and magnitude of the potential impact of any proposals ultimately adopted by the PSC on the business of the Company will depend on the specific details of any plan for increased competition and resolution of the complex issues related to competition at the retail level.

FERC Open Transmission Proposals

In March 1995 FERC proposed new rules which would facilitate the development of competitive wholesale markets by requiring electric utilities to offer "open-access" transmission service on a non-discriminatory basis. A final rule would define the non-discriminatory terms and conditions under which unregulated generators, neighboring utilities, and other suppliers could gain access to a utility's transmission grid to deliver power to wholesale customers. A supplementary release by FERC states the principle that utilities are entitled to full recovery of "legitimate, prudent and verifiable" strandable costs at the state and federal level. This supplementary release concludes that FERC should be the principal forum for addressing wholesale strandable costs, while suggesting state regulatory authorities should address the recovery of strandable costs which may result from retail competition. The FERC sought comments on its proposals in August and October. The Company responded individually and as a member the New York Power Pool (NYPP). The NYPP is actively evaluating the requirements for implementing wholesale competition within the framework of the FERC proposals. Significant changes to NYPP pricing procedures are expected, but their projected effects on the Company's operations and financial performance are not substantial assuming continued vertical integration of the utility industry in



Energy Fuels The Vision

New York State. FERC is continuing to solicit public comments and elicit public involvement on these proposals. A final ruling from FERC is not anticipated before mid-1996. At the present time, the Company cannot predict what effects regulations ultimately adopted by FERC will have, if any, on future operations or the financial condition of the Company.

Gas Utility Competition. Competition in the Company's gas business has existed for some time, as larger customers have had the option of obtaining their own gas supply and transporting it through the Company's distribution system. FERC Order 636 enables the Company and other gas utilities to negotiate directly with gas producers for supplies of natural gas. With the unbundling of services, primary responsibility for reliable natural gas has shifted from interstate pipeline companies to local distribution companies, such as the Company.

PSC Gas Restructuring Case

In October 1993 the PSC initiated a proceeding to address issues involving the restructuring of gas utility services to respond to competition. Subsequently, in December 1994, the PSC issued an order which presented regulatory policies and guidelines for natural gas distributors. Requirements having the greatest impact on the Company are:

- The Company must offer its customers unbundled access to upstream facilities such as storage and transportation capacity on the interstate pipelines with which the Company does business.
- The Company may offer to package an individual supply of gas to an individual customer in cases that would lower the Company's overall cost of supplying gas.
- The Company must offer an aggregation program whereby individual customers could join together in a pool for the purpose of purchasing gas from a supplier, in such cases the Company would still provide the service of distributing gas on the Company's system.
- The PSC allows full recovery of the transition costs resulting from FERC Order 636 and requires that a share of these costs be borne by firm transportation customers.

In November 1995 the Company filed its response to this order. The Company's filing focused on setting transportation rates for an aggregation of all gas customers, reviewing the necessity for minimum gas transportation volumes, providing for the recovery of transition costs associated with FERC Order 636, and establishing requirements for the use of automatic recording meters. The impact on the Company's gas business as a result of this proceeding, however, will depend upon the guidelines and regulations ultimately approved by the PSC. At this time, the Company is unable to predict what regulations will ultimately be adopted by the PSC.

Competition and the Company's Prospective Financial Position. It has been suggested that certain New York State utilities should write down certain regulatory or generating assets in anticipation of the impact of competitive and regulatory changes. The Company currently believes its regulatory and generating assets are probable of recovery in rates, but industry trends have moved more toward competition, and in a purely competitive environment, it is not clear to what extent, if any, writeoffs of such assets may ultimately be necessary (see Note 10 of the Notes to Financial Statements).

Regulatory Assets

The Company has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are then recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by Statement of Financial Accounting Standards No. 71 (SFAS-71). These deferred costs are shown as Regulatory Assets on the Company's Balance Sheet and a discussion and summarization of such Regulatory Assets is presented in Note 10 of the Notes to Financial Statements. Such cost deferral is appropriate under traditional regulated cost-of-service rate setting, where all prudently incurred costs are recovered through rates. In a purely competitive pricing environment, such costs might not have been incurred and could not have been deferred. Accordingly, if the Company's rate setting was changed from a cost-of-service approach, and it was no longer allowed to defer these costs under SFAS-71, these assets would be adjusted for any impairment to recovery (see discussion under Financial Accounting Standards No. 121). In certain cases, the entire amount could be written off.

Strandable Assets

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. Examples include purchase power contracts (e.g., the Kamine/Besicorp Allegany L.P. contract, see Projected Capital and Other Requirements) or high cost generating assets. Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. The amount of potentially strandable assets at December 31, 1995 cannot be determined at this time, but could be significant.

Financial Accounting Standards No. 121

In March 1995, the Financial Accounting Standards Board (FASB) issued Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" (SFAS-121). SFAS-121 amends SFAS-71 to require write-off of a regulatory asset or strandable asset if it is no longer probable that future revenues will cover the cost of the asset. SFAS-121 also requires a company to recognize a loss whenever events or circumstances occur which indicate that the carrying amount of an asset may not be fully recoverable. At December 31, 1995 the Company's regulatory assets totaled $311.2 million. At the current time, the Company believes its regulatory assets are probable of recovery, and, accordingly, the adoption of this accounting standard will not have a material impact on the financial position or results of operations of the Company.

The Company's Response. The growing pace of competition in the energy industry has been a primary focus of management over the past three years. The Company accepts the challenges of this new environment and is responding to the impact of increased competition.

Business Strategy

In May 1995 the Company set a new strategic business direction for the future. Highlights of that strategy include:

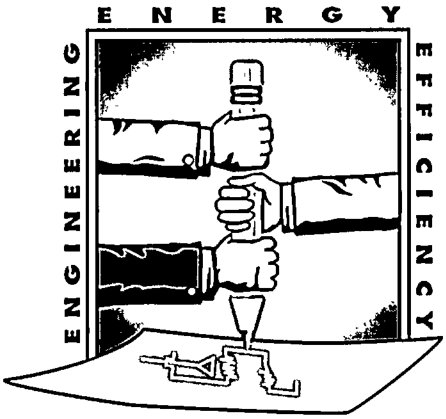
- the focus of the Company will be retail energy services,
- the Company's goal in that business is market leadership, and
- the Company will achieve that goal through operational excellence.

The Company's core business will be the marketing and providing of electricity, natural gas, transmission and distribution services, and other energy-related services to retail customers. A closely-aligned business will be providing gas transmission and gas and electric distribution services to other energy services companies.

The Company is continuously assessing various strategies which may enhance its ability to respond to competitive forces and regulatory change. These strategies are assessed in an effort to provide the greatest possible value to the Company's shareholders and customers giving consideration to changing economic, regulatory, and political circumstances. Such strategies may include business partnerships or combinations with other companies, internal restructuring involving a separation of some or all of the Company's wholesale or retail businesses, and acquisitions of related businesses. No assurances can be given as to whether any of these potential strategies will be pursued, or as to the corresponding results on the financial condition or competitive position of the Company.

Rates and Regulatory Matters

Overview. The Company is subject to PSC regulation of rates, service, and sale of securities, among other matters. The Company is also regulated by FERC on a limited basis, in the areas of interstate sales and exchanges of electricity, intrastate sales of electricity for resale, transmission wheeling service for other utilities, and licensing of hydroelectric facilities. As a licensee of nuclear facilities, the Company is also subject to regulation by the Nuclear Regulatory Commission.



1995 Gas Settlement

The Company's purchased gas expense charged to customers was higher during the 1994-95 heating season compared with prior years, generating substantial customer concern. The action the Company took to reduce rates included refunding the weather normalization adjustment charged to customers in January 1995 and discontinuation of those charges through the remainder of the heating season ending in May 1995. The weather normalization adjustment provides for recovery of fixed charges by producing higher unit rates when the weather is warm and usage is low. Conversely, it would provide lower unit rates during colder periods of high usage.

In December 1994, the PSC instituted a proceeding to review the Company's practices regarding acquisition of pipeline capacity, the deferred costs of the capacity and the Company's recovery of those costs.

In April 1995, the PSC issued a Department of Public Service staff report on the Company's 1994-1995 billing practices and procedures which presented recommendations regarding changes in the Company's natural gas purchasing, billing, meter reading and communication activities.

On August 17, 1995, the Company announced that a negotiated settlement had been reached with the Staff of the PSC and other parties which would resolve various PSC proceedings affecting the Company's gas costs. On October 18, 1995, the PSC approved, effective November 1, 1995, (1) the settlement discussed below, (2) elimination of the weather normalization clause in gas rates and (3) the Company's plan for improving its gas billing procedures (the 1995 Gas Settlement). This settlement affects the rate treatment of various gas costs through October 31, 1998.

Highlights of the 1995 Gas Settlement are:

- The Company will forego, for three years, gas rate increases exclusive of the cost of natural gas and certain cost increases imposed by interstate pipelines.
- The Company has agreed not to charge customers for pipeline capacity costs in 1996, 1997 and 1998 of \$22.5 million, \$24.5 million, and \$27.2 million, respectively. Under FERC rules, the Company may sell its excess transportation capacity in the market. The value of those sales can be used to offset the capacity costs that will not be charged to customers. These amounts that the Company will not be permitted to charge are subject to increase in the event of major increases in the overall cost of pipeline capacity during these years. The foregoing amounts include the cost of capacity to be purchased by replacement shippers. As discussed below, a substantial portion of this capacity is expected to be released and sold in the market pursuant to a marketing agreement with CNG Transmission Corporation (CNG), a supply agreement with MidCon Gas Services Corporation (MGSC), and other individual agreements.
- The Company agreed to write off excess gas pipeline capacity costs incurred through 1995.
- As part of a separate decision, the PSC agreed with the Company's request to eliminate the weather normalization clause effective November 1, 1995. The weather normalization clause had adjusted gas customer billing for abnormal weather variations.

The economic effect of the 1995 Gas Settlement on the Company's 1995 results of operations may be summarized as follows:

Description	Millions of Dollars (Pretax)	Earnings per Share Effect
Elimination of weather normalization charges	$5.8	$(.10)
Foregone gas rate increase scheduled for July 1, 1995	2.8	(.04)
Foregone gas pipeline capacity costs for 1995	8.8	(.15)
Gas pipeline capacity and other costs which were written off in October 1995	23.2	(.40)
Provision for retroactive pipeline charges pending before FERC	3.6	(.06)
Total	$44.2	$(.75)

Under provisions of the 1995 Gas Settlement, the Company faces an economic risk of remarketing $74.2 million of excess gas capacity through 1998. The Company has entered into a marketing agreement with CNG that is expected to result in the release of approximately $29 million of this capacity through the period. CNG will assist the Company in obtaining permanent replacement customers for transportation capacity the Company will not require. To help manage the balance of the excess capacity costs at risk, the Company has retained MGSC which will work with the Company to identify and implement opportunities for temporary and permanent release of surplus pipeline capacity and advise in the management of the Company's gas supply, transportation and storage assets consistent with the goal of providing reliable service and reducing the cost of gas.

The ultimate financial impact of the 1995 Gas Settlement on the Company's business in 1996 and subsequent years will be largely determined by the degree of success achieved by the Company in remarketing its excess gas capacity and in controlling its local gas distribution costs.

1995 Rate Proposal

With the current three-year electric and gas rate plan expiring in July 1996 (see 1993 Rate Agreement below), the Company in July 1995 filed a request with the PSC for new electric rate tariffs commencing in August 1996. Higher electric rates have been requested to cover increases in capital and operating costs that are not provided for in present rates and are not expected to be offset by increased revenues from sales. Highlights of the 1995 Rate Proposal filing are as follows:

- A request for electric rates to be increased by approximately $17.1 million or 2.4 percent annually (based on forecasted retail sales volumes).
- A requested 11.75 percent rate of return on equity.

PSC Staff has proposed that electric rates be decreased 3.5 percent in each of the next two years based on a rate of return on equity of 10.50 percent.

Although the Company's rate application is being litigated before a PSC Administrative Law Judge, the Company has been working with the PSC Staff and others to develop an agreement that could lead to a settlement of the Company's filing, replacing the Company's current rate agreement with a new agreement. The goal is to stabilize customer rates at as low a level as possible and establish guidelines that will allow the Company to assume more risk to take actions that could create increased earnings for shareholders.

The Company is unable to predict whether any settlement will be achieved, or what effect any ultimate PSC decision in this proceeding will have on the Company's results of operation or its financial position. A PSC decision on the Company's rate filing is expected by August 1996. Negotiations were suspended late in 1995 after the various participants failed to reach a preliminary settlement. While the Company continues to believe a settlement of these issues would be in the best interest of all parties, it cannot predict the future course of negotiations.

1993 Rate Agreement

In August 1993 the PSC approved a settlement agreement (1993 Rate Agreement) which determined the Company's rates through June 30, 1996 and includes certain incentive arrangements providing for both rewards and penalties. Under the 1993 Rate Agreement, the PSC approved an electric rate increase of 2.5% ($18.3 million) effective July 1, 1995. Recovery of approximately $20 million of incentive awards earned by the Company has been delayed for future consideration given the competitive environment and the Company's desire to minimize price impacts on its customers. A summary of recent PSC rate decisions under this agreement is included in the table titled Rate Increases.

Flexible Pricing Tariff

Under its flexible pricing tariff for major industrial and commercial electric customers, the Company may negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Under the terms of the 1993 Rate Agreement, the Company would absorb 30 percent of any net revenues lost as a result of such discounts through June 1996, while the remaining 70 percent would be recovered from other customers. The Company has not sought recovery of that 70 percent from other customers. The portion recoverable after June 1996 is expected to be determined by the PSC as it considers the 1995 Rate Proposal. Under the flexible tariff provisions, the Company as of year-end 1995 had negotiated long-term electric supply contracts with twenty of its large industrial and commercial electric customers at discounted rates. The Company is negotiating long-term electric supply contracts with other large customers as the need and opportunity arise. The Company has not experienced any customer loss due to competitive alternative arrangements.

Purchased Gas Undercharges

In March 1994 the PSC approved a December 1993 settlement among the Company, PSC Staff and another party regarding the Company's accounting for certain gas purchases for the period August 1990-August 1992 which resulted in undercharges to gas customers of approximately $7.5 million. The Company wrote off $2.0 million of the undercharges as of December 31, 1993, reducing 1993 earnings by four cents per share, net of tax. In April 1994, the Company wrote off an additional one cent per share, net of tax. Under the 1993 settlement, the Company was to collect $2.6 million from customers over a three-year period. Due to rate increase limitations established in the Company's 1993 Rate Agreement and certain provisions under the 1995 Gas Settlement; however, the Company is precluded from collecting the $2.6 million, and, accordingly, this amount was written off in 1995 and is reflected in Other Deductions on the Statement of Income.

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 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	3.0	9.23	11.50
	July 1, 1995	18,300	2.5	9.30	11.50
Gas	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	7,400	3.0	8.90	11.50
	July 1, 1995	—	—	9.30	11.50

Liquidity and Capital Resources

During 1995 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 of all outstanding short-term borrowings. At December 31, 1995 the Company had cash and cash equivalents of $44.1 million. Capital requirements during 1996 are anticipated to be satisfied primarily from the combination of internally generated funds and temporary cash investments.

Projected Capital and Other Requirements

The Company's capital requirements relate primarily to expenditures for electric generation, including the 1996 replacement of its Ginna steam generators, transmission and distribution facilities, and gas mains and services as well as the repayment of existing debt. The Company has no current plans to install additional baseload generation.

Integrated Resource Plan

The Company's 1992 Integrated Resource Plan (IRP) and 1993 IRP update explored options for complying with the 1990 Clean Air Act Amendments. Future options with regard to generating resources and alternative methods of meeting electric capacity requirements were also examined. Activities have been completed or are currently under way to:

- Modify Units 2, 3, and 4 at Russell Station and Unit 12 at Beebee Station (all coal-fired facilities) to meet federal Environmental Protection Agency standards and Clean Air Act requirements, and
- Replace the two steam generators at the Ginna Nuclear Plant.

As the future of the electric competitive marketplace becomes more clear with the conclusion of the PSC Competitive Opportunities Case, the Company anticipates addressing a new full-scale planning review.

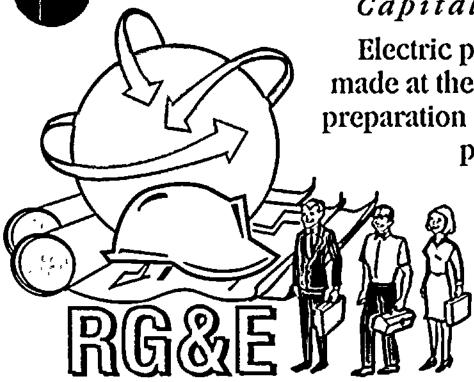
Ginna Steam Generator Replacement

Preparation for replacement of the two steam generators at the Ginna Nuclear Plant began in 1993 and will continue until the replacement in 1996. Much of the preliminary preparation has been done during the normal annual refueling and maintenance outages. The Company anticipates that the 1996 outage for refueling and replacement will begin in April and take about 70 days. Cost of the replacement is estimated at $115 million; about $40 million for the units, about $50 million for installation and the remainder for engineering and other services. Refueling is expected to take place on an 18-month cycle once the new steam generators are installed. The PSC order regarding this project provides that certain costs over $115 million, and savings under that amount, will be shared between the Company and its customers but the Company does not expect to exceed that amount.

Purchased Power Requirement

Under federal and New York State laws and regulations, the Company is required to purchase the electrical output of unregulated cogeneration facilities which meet certain criteria (Qualifying Facilities). The Company was compelled by regulators to enter into a contract with Kamine/Besicorp Allegany L.P. (Kamine) for approximately 55 megawatts of capacity, the circumstances of which are discussed in Note 10 of the Notes to Financial Statements. The Kamine contract and the outcome of related litigation will have an important impact on the Company's electric rates and its ability to function effectively in a competitive environment. The Company has no other long-term obligations to purchase energy from Qualifying Facilities.

Capital Requirements and Electric Operations



Electric production plant expenditures in 1995 included $41 million of expenditures made at the Company's Ginna Nuclear Plant, of which $29 million was incurred for preparation to replace the steam generators. The Company spent $16 million on this project in 1994 and $15 million in 1993. In addition, nuclear fuel expenditures of $16 million were incurred at Ginna during 1995.

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 1995. Expenditures of $1 million during 1995 were also made for the Company's share of nuclear fuel at Nine Mile Two. On April 8, 1995 Nine Mile Two was taken out of service for a scheduled refueling outage and resumed full operation on June 2, 1995, the shortest refueling in the plant's history. The next refueling outage for Nine Mile Two is scheduled for late 1996.

Electric transmission and distribution expenditures, as presented in the Capital Requirements table, totaled $22 million in 1995, of which $20.4 million was for the upgrading of electric distribution facilities to meet the energy requirements of new and existing customers.

Capital Requirements and Gas Operations

The Empire State Pipeline (Empire), an intrastate natural gas pipeline between Grand Island and Syracuse, New York is subject to PSC regulation and commenced operation in November 1993. The Company is participating as an equity owner of Empire through its wholly-owned subsidiary, Energyline Corporation (Energyline), along with subsidiaries of Coastal Corporation and Westcoast Energy Inc. Energyline has a total obligation of $20 million in Empire, made up of a $10.3 million equity investment, and $9.7 million in commitments under a credit agreement.

Construction requirements for gas property totaled $14 million in 1995 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. 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. A more detailed discussion concerning the Company's environmental matters, including a discussion of the federal Clean Air Act Amendments, can be found in Note 10 of the Notes to Financial Statements.

Redemption of Securities

In addition to first mortgage bond maturities and mandatory sinking fund obligations over the past three years, discretionary redemption of securities totaled $120 million in 1993, $24.5 million in 1994, and $1 million in 1995. There was no mandatory redemption of securities in 1995.

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 1993 to 1995 and the current estimate of capital requirements through 1998 are summarized in the Capital Requirements table.

Capital Requirements

Type of Facilities	Actual 1993	1994	1995	Projected 1996	1997	1998
			(Millions of Dollars)			
Electric Property						
Production	$ 54	$ 42	$ 48	$ 68	$ 18	$ 19
Transmission and Distribution	29	26	22	30	28	26
Street Lighting and Other	2	1	3	1	1	1
Subtotal	85	69	73	99	47	46
Nuclear Fuel	16	16	17	20	20	15
Total Electric	101	85	90	119	67	61
Gas Property	20	20	14	16	18	18
Common Property	21	12	4	13	13	14
Total	142	117	108	148	98	93
Carrying Costs						
Allowance for Funds Used During Construction (AFUDC)	2	2	3	2	1	1
Deferred Financing Charges Included in Other Income	1	-	-	-	-	-
Total Construction Requirements	145	119	111	150	99	94
Securities Redemptions, Maturities and Sinking Fund Obligations*	212	52	1	18	30	40
Total Capital Requirements	$357	$171	$112	$168	$129	$134

*Excludes prospective refinancings.

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.

Financing and Capital Structure

The Company had no debt maturity or sinking fund obligations in 1995 and had no public issuance of securities during the year. Capital requirements in 1995 were satisfied primarily by a combination of internally generated funds and proceeds from the issuance of new shares of Common Stock through its Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan). The Company foresees modest near-term financing requirements. Investments in short-term securities were approximately $37.5 million at December 31, 1995. Depending upon economic and market conditions at the time, the Company could use proceeds from these securities to meet construction requirements, undertake debt and/or preferred stock redemptions, or consider investments in unregulated businesses. With an increasingly competitive environment, the Company believes maintaining a high degree of financial flexibility is critical. In this regard, the Company's long-term objective is to control capital expenditures and to move to a less leveraged capital structure.

The Company anticipates utilizing its credit agreements and unsecured lines of credit 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, redeem 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, and other factors.

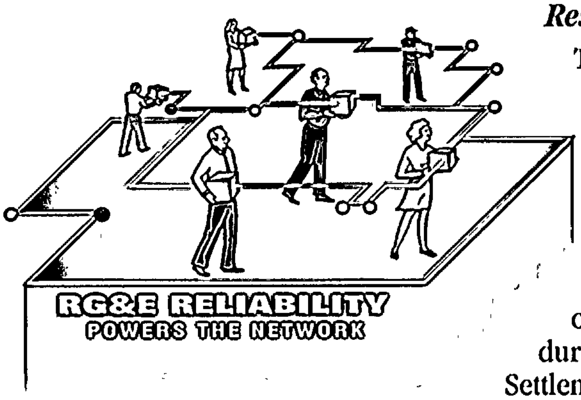
Financing

For information with respect to short-term borrowing arrangements and limitations, see Note 9 of the Notes to Financial Statements.

During 1995 approximately 783,000 new shares of Common Stock were sold through the Company's ADR Plan and an employee stock purchase plan, providing $17.1 million to help finance its capital expenditures program. New shares issued in 1995 and 1994 were purchased from the Company at a market price above the book value per share at the time of purchase. These plans permit the Company to issue new shares to participants or to purchase outstanding shares on the open market.

Capital Structure

The Company's retained earnings at December 31, 1995 were $70.3 million, a decrease of approximately $4.2 million compared with a year earlier. Retained earnings were reduced by approximately $15 million in October 1995 resulting from a writeoff of certain gas costs, as discussed under the heading 1995 Gas Settlement. Common equity (including retained earnings) comprised 45.3 percent of the Company's capitalization at December 31, 1995, with the balance being comprised of 7.3 percent preferred equity and 47.4 percent long-term debt. Capitalization at December 31, 1995, including $18.0 million of long-term debt due within one year, was comprised of 44.9 percent common equity, 7.2 percent preferred equity, and 47.9 percent long-term debt. 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 10 of the Notes to Financial Statements. As financial market conditions warrant, the Company may, from time to time, issue securities to permit early redemption of higher-cost senior securities. The Company is reviewing its financing strategies as they relate to debt and equity structures in the context of the new competitive environment and the ability of the Company to shift from a fully regulated to a more competitive organization.



Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1995 to 1994 and 1994 to 1993. The Notes to Financial Statements contain additional information.

Operating Revenues and Sales

Compared with a year earlier, operating revenues were nearly unchanged in 1995 after rising five percent in 1994. Gas operating revenues declined in 1995 due to the milder weather during the first quarter of the year and as a result of the 1995 Gas Settlement discussed earlier. Customer electric revenue increased, reflecting higher kilowatt-hour sales and recovery of higher fuel costs. Revenues from the sale of electric energy to other utilities were up due, in part, to a new FERC-approved tariff which has greatly facilitated the Company's participation in two-party sales, or sales which are independent of the New York Power Pool. Details of the revenue changes are presented in the Operating Revenues table. As presented in this table, the base cost of fuel has been excluded from customer consumption and is included under fuel costs, revenue taxes and deferred fuel costs are included as a part of other revenues, and unbilled revenues are included in each caption as appropriate.

Operating Revenues

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	Electric Department 1995	Electric Department 1994	Gas Department 1995	Gas Department 1994
Customer Revenues (Estimated) from:				
Rate Increases	$15,704	$18,647	$ 1,883	$ 4,155
Fuel Costs	16,393	3,171	(26,505)	29,989
Weather Effects (Heating & Cooling)	1,397	(1,166)	(1,525)	(3,362)
Customer Consumption	8,968	1,726	8,433	(2,406)
Other	(4,028)	(3,185)	(14,484)	3,977
Total Change in Customer Revenues	38,434	19,193	(32,198)	32,353
Electric Sales to Other Utilities	9,278	244	—	—
Total Change in Operating Revenues	$47,712	$19,437	$(32,198)	$32,353

Changes in fuel cost revenues, which include purchased power revenues, normally have been earnings neutral in the past. Under the 1993 Rate Agreement, however, fuel clause provisions 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 amounts. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were increased by $3.9 million in 1994 and $6.6 million in 1995, reflecting, in part, actual experience in both electric fuel costs and generation mix compared with rate assumptions. Deferred costs associated with the DOE's assessment for future uranium enrichment decontamination are also being recovered through the Company's electric fuel adjustment clauses. Certain transition costs incurred by gas supply pipeline companies and billed to the Company are recovered through the Company's gas fuel adjustment provisions.

A reconciliation of gas costs incurred and gas costs billed to customers is done annually, as of August 31, and the excess or deficiency is normally refunded to or recovered from customers during a subsequent period. As part of the 1995 Gas Settlement, the Company agreed not to collect from customers and to write off $23.2 million of gas costs which had previously been incurred.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from spaceheating customers comprise about 90 to 95 percent of total gas operating revenues. Weather in the Company's service area during 1994 and 1995 was warmer than normal, with the weather during 1995 being 2.4 percent warmer than 1994 on a calendar-month heating degree day basis. With elimination of the weather normalization clause in the Company's gas tariff, abnormal weather variations may have a more pronounced effect on future gas revenues. Warmer than normal summer weather during 1995 and 1994 boosted electric energy sales to meet the demand for air conditioning usage.

Compared with a year earlier, kilowatt-hour sales of energy to retail customers were up 2.8 percent in 1995, after remaining nearly flat in 1994. Sales to industrial customers led the increase. This gain was driven by one large industrial customer who is purchasing more electric power as an alternative to power produced at its own plant. Electric demand for air conditioning usage had a significant impact on kilowatt-hour sales in 1994 and 1995. The Company had a net gain of nearly 2,600 new electric customers during 1995, including over 400 new commercial customers.

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. In contrast to 1994, revenues from sales to other electric utilities grew in 1995 reflecting increased kilowatt-hour sales and higher rates. In addition to sales through the New York Power Pool, the Company increased its participation in two-party sales, as discussed earlier. With the possibility of 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 is an important component of the Company's marketing mix. Company facilities are used to distribute this gas, which amounted to 14.6 million dekatherms in 1995 and 13.6 million dekatherms in 1994. These purchases have caused decreases in customer revenues, with offsetting decreases in purchased gas expenses, but in general do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of buying and transporting gas to the Company's city gate, 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. The Company's objective is eventually to make gas transportation a viable option for every customer on its system. Under two new gas transportation tariffs currently pending before the PSC in its Gas Restructuring Case, minimum throughput levels to qualify for such service would be totally eliminated by July 1998, thereby allowing all customers to qualify for gas transportation service and to choose their own sources of gas supply. If approved by the PSC, these tariffs will be in place by July 1996.

Therms of gas sold and transported, including unbilled sales, were nearly flat in 1995, after dropping two percent in 1994. These changes reflect, primarily, the effect of weather variations on therm sales to customers with spaceheating. If adjusted for normal weather conditions, residential gas sales would have increased about 1.7 percent in 1995 over 1994, while nonresidential sales, including gas transported, would have increased approximately 2.0 percent in 1995. The average use per residential gas customer, when adjusted for normal weather conditions, was slightly up in 1995, following a modest decrease in 1994.

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

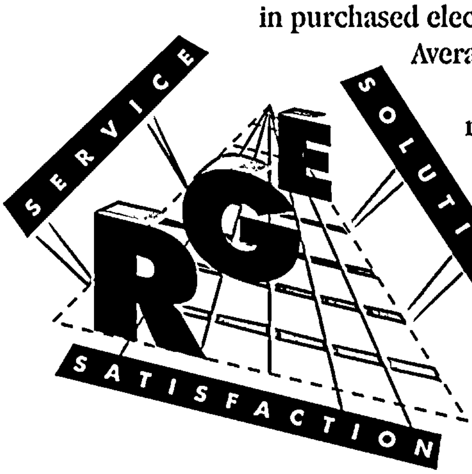
Operating Expenses

Operating expenses in 1995 reflect the first complete year of savings associated with the Company's early retirement programs in 1993 and 1994. The Company's continuing efforts to curtail increases in maintenance and other operation expenses are also reflected in 1995 results. Operating expenses are summarized in the table titled Operating Expenses.

Operating Expenses		
Increase or (Decrease) from Prior Year		
(Thousands of Dollars)	1995	1994
Fuel for Electric Generation	$ (771)	$ (910)
Purchased Electricity	17,165	5,439
Gas Purchased for Resale	(26,628)	27,506
Other Operation	18,011	515
Maintenance	(5,843)	(6,624)
Depreciation and Amortization	4,132	3,284
Taxes Charged to Operating Expenses		
Local, State and Other Taxes	4,117	2,886
Federal Income Tax	4,970	11,915
Total Change in Operating Expenses	$15,153	$44,011

Energy Costs—Electric. Lower fuel expense for electric generation in 1995 compared with a year earlier reflects primarily a drop in the average cost of coal used to generate power. Total Company electric generation was up 4.5 percent in 1995. For the 1994 comparison period, 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. The average cost of nuclear fuel decreased in 1994 and was up slightly in 1995.

The Company normally purchases electric power to supplement its own generation when needed to meet load or reserve requirements, and when such power is available at a cost lower than the Company's production cost. Under a contract with Kamine, however, the Company has been required to purchase unneeded energy at uneconomical rates (see Note 10 of the Notes to Financial Statements). The Company purchased 337 thousand megawatt-hours of energy from Kamine at a total price of $16.6 million in 1995. For the 1994 comparison period, the increase in purchased electricity expense was caused by an increase in kilowatt-hours purchased. Average rates for purchased electricity were up in 1995 after declining in 1994.



Energy Management and Costs—Gas. The Company purchases all of its required gas supply directly from numerous producers and marketers under contracts containing varying terms and conditions. The Company currently holds firm transportation capacity on ten major natural gas 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 system (7.2 billion cubic feet) and on the ANR Pipeline system (8.4 billion cubic feet) which is used to help satisfy its customers' winter demand requirements.

The Company acquires gas supply and transportation capacity based on its requirements to meet peak loads which occur in the winter months. The Company is committed to transportation capacity on Empire and the CNG pipeline system, as well as to upstream pipeline transportation and storage services. The combined CNG and Empire transportation capacity exceeds the Company's current requirements. This temporary excess has occurred largely due to the Company's initiatives to diversify its supply of gas and the industry changes and increasing competition resulting from the implementation of FERC Order 636.

As a result of the restructuring of the gas transportation industry by FERC pursuant to Order No. 636 and related decisions, there have been and will be a number of changes in the gas portion of the Company's business over the next several years. These changes will require the Company to pay a share of certain transition costs incurred by the pipelines as a result of the FERC-ordered industry restructuring. For additional information with respect to these transition costs, see Note 10 of the Notes to Financial Statements.

Gas purchased for resale expense declined in 1995 driven by a reduced volume of purchased gas resulting from a warmer than normal heating season. In addition, average purchased gas rates declined in 1995 compared with a year earlier, primarily due to lower commodity costs. Despite a decrease in the volume of gas purchased, gas purchased for resale expense was up in 1994 reflecting higher average purchased gas rates compared with 1993.

Operating Expenses, Excluding Fuel. Other operation expense increased approximately $18.0 million in 1995, after remaining nearly flat in 1994. An additional expense accrual for doubtful accounts increased operating expenses by $15.0 million in 1995. This expense was partially offset by lower costs for payroll, employee welfare, and materials and supplies due, in part, to Company cost control efforts and the work reduction programs undertaken in 1994. The additional reserve in 1995 for doubtful accounts was recognized to provide for increases in past due accounts. The change in other operation expenses for the 1994 comparison period reflects increased demand side management and uncollectible expenses offset by lower payroll and welfare expense.

Lower maintenance expense in both comparison periods reflects reduced payroll and contractor costs.

For both comparison periods, the increase in depreciation expense reflects an increase in depreciable plant. When completed, replacement of the steam generators at the Ginna Nuclear Plant is anticipated to increase depreciation expense by approximately $11 million annually.

Taxes Charged To Operating Expenses. The increase in local, state and other taxes in the 1995 comparison period reflects certain assessments for prior years' taxes. The 1994 comparison period reflects primarily an increase in revenues combined with increased property tax rates and generally higher property assessments.

See Note 2 of the Notes to Financial Statements for an analysis of federal income taxes.

Other Statement of Income Items

Variations in non-operating federal income tax reflect mainly accounting adjustments related to retirement enhancement programs (see Earnings Summary), regulatory disallowances, and employee performance incentive programs (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 and the third quarter of 1994. These programs are discussed under Earnings Summary.

Other—Net Income and Deductions for 1993 and 1994 result mainly from the recognition of employee performance incentive programs in each of those years. These programs recognize employees' achievements in meeting corporate goals and reducing expenses. For the 1995 comparison period, Other—Net Income and Deductions also reflects recognition of the employee incentive program and additional depreciation of the Empire project to recognize the difference between a rateable method of computation versus a lesser amount currently included in rates.

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 1993-1995. The average short-term debt outstanding decreased in 1994 and 1995.

Dividend Policy

The current annual dividend rate on the Company's Common Stock is $1.80 per share. 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. The Company believes that future dividend payments will need to be evaluated in the context of maintaining the financial strength necessary to operate in a more competitive and uncertain business environment. This will require consideration, among other things, of a dividend payout ratio that is lower over time, reevaluating assets and managing greater fluctuation in revenues. While the Company does not presently expect the impact of these factors to affect the Company's ability to pay dividends at the current rate, future dividends may be affected.

Officer Appointments

J. Burt Stokes

In January 1996, J. Burt Stokes was appointed Senior Vice President, Corporate Services and Chief Financial Officer. He comes to RG&E from a position as Chief Financial Officer and Acting Chief Executive Officer for General Railway Signal Corporation (GRS). Mr. Stokes will have responsibility for financial services, human resource services and legal.

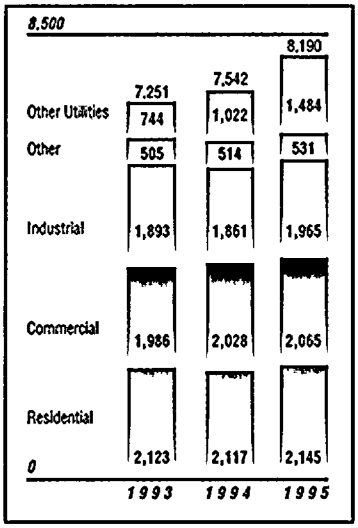
Jessica S. Raines

Jessica S. Raines was appointed Auditor in September, 1995. The corporate audit group reviews the company's business units for adherence to corporate policies, compliance with regulatory guidelines, and ensures that a sound internal control system is in place. Ms. Raines was formerly Vice President and Client Service Partner at Chase Manhattan Bank, N.A. in New York City.

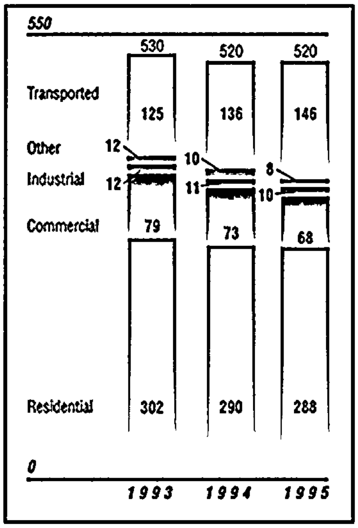
Financial Reports

Financial Profile

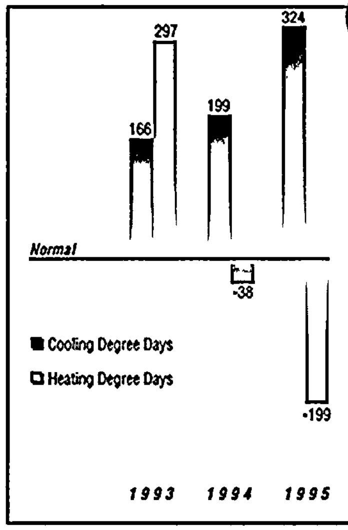
Electric Market Profile
(thousands of mwh sold)



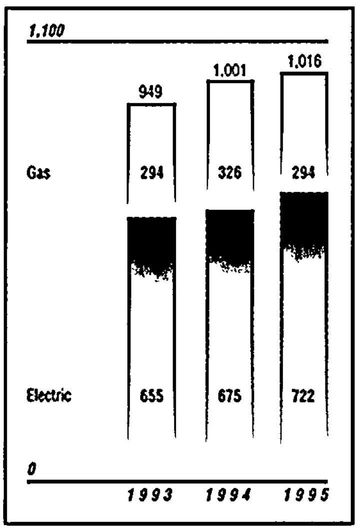
Gas Market Profile
(millions of therms sold and transported)



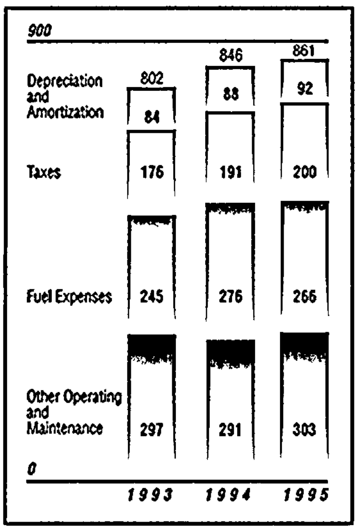
Degree Day Variations From Normal



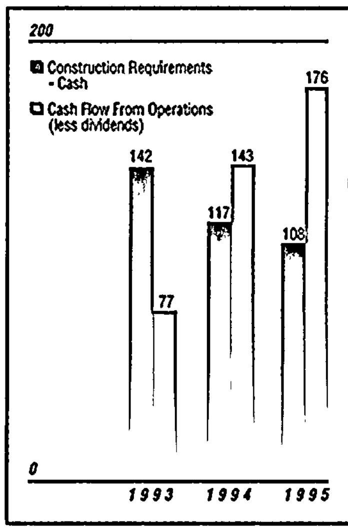
Operating Revenues
(millions of dollars)



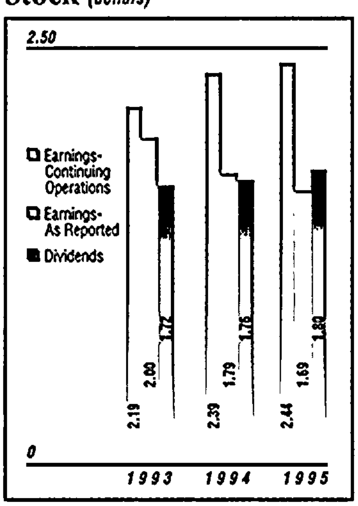
Operating Expenses
(millions of dollars)



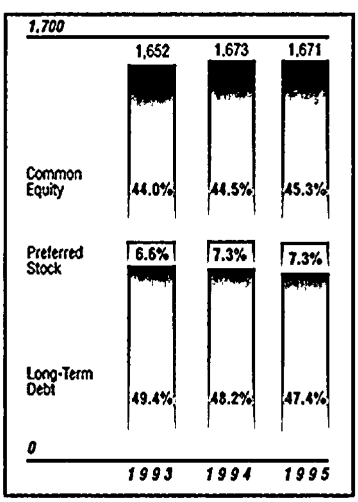
Cash Flow
(millions of dollars)



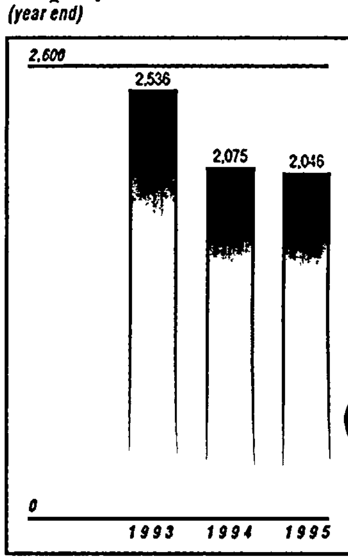
Earnings And Dividends Per Share Of Common Stock *(dollars)*



Capitalization At December 31
(millions of dollars)



Employees
(year end)



Consolidated Statement of Income

(Thousands of Dollars) Year Ended December 31	1995	1994	1993
Operating Revenues			
Electric	$ 696,582	$ 658,148	$ 638,955
Gas	293,863	326,061	293,708
	990,445	984,209	932,663
Electric sales to other utilities	25,883	16,605	16,361
Total Operating Revenues	1,016,328	1,000,814	949,024
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	44,190	44,961	45,871
Purchased electricity	54,167	37,002	31,563
Gas purchased for resale	167,762	194,390	166,884
Total Fuel Expenses	266,119	276,353	244,318
Operating Revenues Less Fuel Expenses	750,209	724,461	704,706
Other Operating Expenses			
Operations excluding fuel expenses	253,907	235,896	235,381
Maintenance	49,226	55,069	61,693
Depreciation and amortization	91,593	87,461	84,177
Taxes—local, state and other	133,895	129,778	126,892
Federal income tax	66,215	61,245	49,330
Total Other Operating Expenses	594,836	569,449	557,473
Operating Income	155,373	155,012	147,233
Other Income and Deductions			
Allowance for other funds used during construction	585	396	153
Federal income tax	16,948	16,259	9,827
Regulatory disallowances.	(26,866)	(600)	(1,953)
Pension Plan Curtailment	—	(33,679)	(8,179)
Other, net	(14,931)	(4,853)	(7,074)
Total Other Income and (Deductions)	(24,264)	(22,477)	(7,226)
Interest Charges			
Long term debt	53,026	53,606	56,451
Other, net	9,056	6,566	6,707
Allowance for borrowed funds used during construction	(2,901)	(2,012)	(1,714)
Total Interest Charges	59,181	58,160	61,444
Net Income	71,928	74,375	78,563
Dividends on Preferred Stock	7,465	7,369	7,300
Earnings Applicable to Common Stock	$ 64,463	$ 67,006	$ 71,263
Weighted Average Number of Shares for Period (000's)	38,113	37,327	35,599
Earnings per Common Share	$ 1.69	$ 1.79	$ 2.00

Consolidated Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31	1995	1994	1993
Balance at Beginning of Period	$ 74,566	$ 75,126	$ 66,968
Add			
Net Income	71,928	74,375	78,563
Adjustment Associated with Stock Redemption	—	(1,398)	(933)
Total	146,494	148,103	144,598
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock—at required rates (Note 7)	7,465	7,369	7,300
Common stock	68,699	66,168	62,172
Total	76,164	73,537	69,472
Balance at End of Period	$ 70,330	$ 74,566	$ 75,126
Cash Dividends Declared per Common Share	$ 1.80	$ 1.77	$ 1.73

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

Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1995	1994
Assets		
Utility Plant		
Electric	$2,342,981	$2,284,63[illegible]
Gas	382,071	370,20[illegible]
Common	135,526	135,975
Nuclear fuel	207,525	190,337
	3,068,103	2,981,151
Less: Accumulated depreciation	1,345,552	1,263,637
Nuclear fuel amortization	173,326	159,461
	1,549,225	1,558,053
Construction work in progress	121,725	128,860
Net Utility Plant	1,670,950	1,686,913
Current Assets		
Cash and cash equivalents	44,121	2,810
Accounts receivable, net of allowance for doubtful accounts: 1995—$11,950; 1994—$950	121,123	110,417
Unbilled revenue receivable	64,169	54,270
Materials and supplies, at average cost:		
Fossil fuel	8,101	7,908
Construction and other supplies	10,223	13,264
Gas stored underground	20,326	24,315
Prepayments	24,533	23,535
Total Current Assets	292,596	236,519
Investment in Empire	38,879	38,560
Deferred Debits		
Unamortized debt expense	16,712	18,343
Nuclear generating plant decommissioning fund	71,540	49,011
Nine Mile Two deferred costs	32,411	33,462
Deferred finance charges—Nine Mile Two	19,242	19,242
Other deferred debits	21,857	19,214
Regulatory assets:		
Income taxes	188,599	205,794
Uranium enrichment decommissioning deferral	18,707	20,169
Deferred ice storm charges	16,553	19,111
FERC 636 transition costs	40,965	32,479
Demand side management costs	14,759	19,807
Deferred fuel costs—gas	—	33,84[illegible]
Other regulatory assets	31,623	33,72[illegible]
Total Regulatory Assets	311,206	364,932
Total Deferred Debits	472,968	504,204
Total Assets	$2,475,393	$2,466,196
Capitalization and Liabilities		
Capitalization		
Long term debt—mortgage bonds	$ 624,332	$ 643,278
—promissory notes	91,900	91,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	55,000	55,000
Common shareholders' equity:		
Common stock	687,518	670,569
Retained earnings	70,330	74,566
Total Common Shareholders' Equity	757,848	745,135
Total Capitalization	1,596,080	1,602,313
Long Term Liabilities (Department of Energy)		
Nuclear waste disposal	75,077	70,895
Uranium enrichment decommissioning	15,810	16,931
Total Long Term Liabilities	90,887	87,826
Current Liabilities		
Long term debt due within one year	18,000	—
Short term debt	—	51,600
Note Payable—Empire	29,600	29,600
Accounts payable	52,578	42,934
Dividends payable	19,170	18,818
Taxes accrued	18,638	3,471
Interest accrued	12,844	11,967
Other	31,508	22,937
Total Current Liabilities	182,338	181,327
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	377,652	402,894
Deferred finance charges—Nine Mile Two	19,242	19,242
Pension costs accrued	71,580	75,91[illegible]
Other	137,614	96,68[illegible]
Total Deferred Credits and Other Liabilities	606,088	594,730
Commitments and Other Matters (Note 10)	—	—
Total Capitalization and Liabilities	$2,475,393	$2,466,196

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

Rochester Gas and Electric Corporation

Consolidated Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31	1995	1994*	1993*
Cash Flow from Operations			
Net income	$ 71,928	$ 74,375	$ 78,563
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	91,593	87,461	84,177
Amortization of nuclear fuel	17,982	18,048	18,861
Deferred fuel—electric	(7,213)	(1,967)	(2,072)
Deferred fuel—gas	10,645	(28,691)	(13,453)
Deferred income taxes	(8,047)	13,193	15,232
Allowance for funds used during construction	(3,486)	(2,408)	(1,867)
Unbilled revenue, net	(9,899)	7,060	(5,107)
Deferred ice storm costs	2,558	2,510	2,576
Nuclear generating plant decommissioning fund	(8,837)	(8,594)	(8,558)
Pension costs accrued	6,280	43,942	11,641
Post employment benefit internal reserve	4,636	5,287	4,174
Research and development amortization	2,860	183	105
Rate settlement amortizations	9,521	8,943	—
Regulatory disallowance	26,866	600	1,953
Changes in certain current assets and liabilities:			
Accounts receivable	(10,706)	(5,664)	(12,461)
Materials and supplies—gas stored underground	3,989	14,674	(28,991)
—other, net	2,848	(1,545)	5,776
Taxes accrued	15,167	(3,001)	(7,271)
Accounts payable	9,644	(9,662)	12,018
Interest accrued	877	(988)	(2,506)
Other current assets and liabilities, net	8,762	317	6,113
Other, net	13,823	1,508	(13,686)
Total Operating	$ 251,791	$ 215,581	$ 145,217
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$ (95,911)	$(103,737)	$(125,744)
Nuclear fuel additions	(17,122)	(15,890)	(15,530)
Less: Allowance for funds used during construction	3,486	2,408	1,867
Additions to Utility Plant	(109,547)	(117,219)	(139,407)
Proceeds from retirement of plant	11,477	—	—
Investment in Empire—net	(319)	—	884
Other, net	(34)	(150)	(1,907)
Total Investing	$ (98,423)	$(117,369)	$(140,430)
Cash Flow from Financing Activities			
Proceeds from:			
Sale/Issue of common stock	$ 17,074	$ 17,369	$ 61,254
Sale of preferred stock	—	25,000	—
Sale of long term debt, mortgage bonds	—	—	200,000
Short term borrowings	(51,600)	(16,500)	17,300
Retirement of long term debt	(1,000)	(33,750)	(200,249)
Retirement of preferred stock	—	(18,000)	(12,000)
Capital stock expense	(125)	1,028	(615)
Dividends paid on preferred stock	(7,465)	(7,328)	(7,548)
Dividends paid on common stock	(68,347)	(65,457)	(60,893)
Other, net	(594)	(91)	(1,468)
Total Financing	$(112,057)	$ (97,729)	$ (4,219)
Increase in cash and cash equivalents	$ 41,311	$ 483	$ 568
Cash and cash equivalents at beginning of year	$ 2,810	$ 2,327	$ 1,759
Cash and cash equivalents at end of year	$ 44,121	$ 2,810	$ 2,327

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31	1995	1994	1993
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 56,592	$ 57,186	$ 60,852
Income taxes paid	$ 43,500	$ 28,411	$ 32,779

*Reclassified for comparative purposes.
The accompanying notes are an integral part of the financial statements.

Electric Corporation

NOTE I

Summary of Accounting Principles

General.

The Company supplies electric and gas services wholly within the State of New York. It produces and distributes electricity and distributes gas in parts of nine counties centering about the City of Rochester. 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 ratemaking and accounting practices and policies of the PSC. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

Principles of Consolidation.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries Roxdel and Energyline. All intercompany balances and transactions have been eliminated.

Energyline Corporation, which is a wholly-owned subsidiary, 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. The Company has authority to make a net investment of up to $20 million in Empire. In June 1993 Empire secured a $150 million credit agreement, a portion of the proceeds of which were used to finance approximately 75% of the total construction cost and initial operating expenses. Energyline has a total obligation of $20 million in the Empire State Pipeline, made up of a $10.3 million equity investment, and $9.7 million in commitments under the credit agreement.

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 customers and the Company will share the effects of any variation from forecast monthly unit fuel costs on a 50%/50% basis up to 60 basis points of common equity or approximately a $7.0 million cumulative annual gain or loss to the Company. Thereafter, 100% of additional fuel clause adjustment amounts are assigned to customers. The electric fuel cost adjustment also provides that any variation from forecast margins below $4.1 million or above $7.1 million on sales to electric utilities be shared with retail customers on a 50%/50% basis.

In addition, there is a similar 80%/20% 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. The December 31, 1995 balance recoverable from customers is $9.3 million. The Company is not currently recognizing ERAM amounts as part of income. The ultimate recognition, if any, will be determined as a part of the current rate filing with the PSC.

In prior years, retail customers who use gas for spaceheating were 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. Weather normalization adjustments lowered gas revenues in 1994 and 1993 by approximately $1.2 million in each year. On January 25, 1995 the Company suspended the weather normalization adjustment in an effort to mitigate high billings due to the warm weather, and as discussed in Note 10, the suspension became permanent. This decreased 1995 pre-tax earnings from gas operations by $5.8 million.

The Company practices gas cost deferral accounting. 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 period.

Utility Plant, Depreciation and Amortization.

The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect 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 an annual depreciation provision of 2.9% in the three year period ended December 31, 1995. Reported other income deductions includes an additional charge of approximately $5 million to recognize the difference between a rateable method of computation versus a lesser amount currently included in rates for the Empire Pipeline.

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 Consolidated 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 ranged from 5.0% to 3.9% during the three-year period ended December 31, 1995.

The Company did not accrue AFUDC on a portion of its investment in Nine Mile Two for which a cash return was allowed. Instead amounts were accumulated in deferred debit and credit accounts for use in conjunction with a rate phase-in plan equal to the amount of AFUDC which was no longer accrued.

Federal Income Tax.

Statement of Financial Accounting Standards (SFAS) 109, Accounting for Income Taxes, was adopted by the Company during the first quarter of 1993 (see Note 2).

(Note 1 continued on page 28)

(continued from page 27)

Cash and Cash Equivalents.

Cash and cash equivalents consist of cash and short-term commercial paper. These investments have original maturity not exceeding three months. Such investments are stated at cost, which approximates fair value, and are considered cash equivalents for financial statement purposes.

Investments in Debt and Equity Securities.

SFAS-115, Accounting for Certain Investments in Debt and Equity Securities was adopted by the Company in 1994 and requires that debt and equity securities not held to maturity or held for trading purposes be recorded at fair value with unrealized gains and losses excluded from earnings and recorded as a separate component of shareholders' equity. The Company's accounting policy, as prescribed by the PSC, with respect to its nuclear decommissioning trusts is to reflect the trusts' assets at market value and reflect unrealized gains and losses as a change in the corresponding accrued decommissioning liability.

Futures Contracts.

The Company periodically hedges natural gas in storage against possible changes in price. Hedges are always backed by gas commodity in storage, and gains or losses resulting from these transactions are deferred until the corresponding gas is withdrawn from storage and delivered to customers. The Company has no open hedge contracts outstanding at December 31, 1995.

Allowance for Doubtful Accounts.

The Company's practice is to reserve an amount for doubtful accounts that corresponds to its write-off history. Recently, the Company experienced an increase in write-offs and extended collection periods. Accordingly, an additional $11 million was reserved in 1995.

Research and Development Cost.

Research and Development charge to expense for the years 1995, 1994, and 1993 was $5.2 million, $7.3 million, and $8.3 million respectively.

Sale of Property.

During 1995, the Company sold property at the location of its former operation center for approximately $11.5 million and entered into a 3 year lease-back arrangement with the buyer. The gain on the sale of the property has been deferred pending disposition by the PSC.

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 ratemaking process. The following is a summary of income tax expense for the three most recent years.

(Thousands of Dollars)	1995	1994	1993
Charged to operating expense:			
Current	$65,368	$35,658	$33,453
Deferred	847	25,587	15,877
Total	66,215	61,245	49,330
Charged (Credited) to other income:			
Current	(9,996)	(7,419)	(9,182)
Deferred	(4,520)	(6,408)	1,787
Investment tax credit	(2,432)	(2,432)	(2,432)
Total	(16,948)	(16,259)	(9,827)
Total Federal income tax expense	$49,267	$44,986	$39,503

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

(Thousands of Dollars)	1995		1994		1993	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$ 71,928		$ 74,375		$ 78,563	
Add: Federal income tax expense	49,267		44,986		39,503	
Income before Federal income tax	$121,195		$119,361		$118,066	
Computed tax expense	$ 42,418	35.0	$ 41,776	35.0	$ 41,323	35.0
Increases (decreases) in tax resulting from:						
Difference between tax depreciation and amount deferred	7,197	6.0	6,685	5.6	6,337	5.4
Investment tax credit	(2,432)	(2.0)	(2,432)	(2.0)	(2,432)	(2.1)
Miscellaneous items, net	2,084	1.7	(1,043)	(0.9)	(5,725)	(4.8)
Total Federal income tax expense	$ 49,267	40.7	$ 44,986	37.7	$ 39,503	33.5

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

(Thousands of Dollars)	1995	1994	1993
Nuclear decommissioning	$(14,797)	$(13,390)	$(11,518)
Nine Mile disallowance	(5,351)	(10,276)	(15,200)
Alternate minimum tax	0	(9,584)	(27,908)
Accelerated depreciation	197,952	184,941	164,821
Investment tax credit	31,143	32,723	34,305
Deferred ice storm charges	4,035	4,930	5,642
Depreciation previously flowed through	183,077	200,956	246,127
Gas storage demand charges	(6,076)	0	0
Other	(12,331)	12,594	29,379
Total	$377,652	$402,894	$425,648

The Company adopted SFAS-109 "Accounting for Income Taxes" in 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, 1995 and 1994 was $189 million and $206 million, respectively. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

(Note 2 continued on page 30)

(continued from page 29)

As of December 31, 1995, the regulatory asset recognized by the Company as a result of adopting SFAS-109 is attributed to $166 million in depreciation, $21 million to property taxes, $18 million of deferred finance charges—Nine Mile Two and $4 million of Miscellaneous items offset by $17 million attributed to investment tax credits and $3 million of revenue taxes.

NOTE 3

Pension Plan and Other Postemployment 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. 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)	
	1995	1994
Accumulated benefit obligation, including vested benefits of $407.8 in 1995 and $330.5 in 1994	$(424.5)*	$(354.8)*
Projected benefit obligation for service rendered to date	$(515.9)*	$(433.5)*
Less—Plan assets at fair value, primarily listed stocks and bonds	520.0	451.7
Plan assets in excess of projected benefits	4.1	18.2
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	(91.1)	(110.9)
Prior service cost not yet recognized in net periodic pension cost	12.5	13.4
Unrecognized net obligation at December 31	2.9	3.4
Pension costs accrued	$ (71.6)	$ (75.9)**

*Actuarial present value.
**Includes $43.3 million pension plan curtailment charge.

Net pension cost included the following components:

		(Millions)	
	1995	1994	1993
Service cost—benefits earned during the period	$ 6.0	$ 8.2	$ 8.7
Interest cost on projected benefit obligation	35.4	32.2	30.0
Actual return on plan assets	(101.1)	0.8	(60.2)
Net amortization and deferral	56.1	(40.0)	24.3
Net periodic pension (credit) cost	$ (3.6)	$ 1.2	$ 2.8

During 1994, the Company offered to its employees a Temporary Retirement Enhancement Program (TREP 3). A total of 399 employees elected to participate in TREP 3 resulting in a net curtailment charge of $43.3 million ($9.6 million deferred for collection from customers), including $71.1 million cost of the enhanced benefit offset by a curtailment gain of $27.8 million. In connection with the curtailment, the Company revalued the projected benefit obligation as of September 30, 1994 utilizing a current discount rate of 8.25%.

The projected benefit obligation at December 31, 1995 and December 31, 1994 assumed discount rates of 6.75% and 8.50%, respectively, and long-term rate of increase in future compensation levels of 5.00% and 6.00%, respectively. The assumed long-term rate of return on plan assets was 8.50%. 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 1995, 1994, and 1993 pension cost reflects adoption of the Statement's provisions which, among other things, require 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 1995, the health care benefit consisted of a contribution of up to $200 per retiree 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.

The Company adopted SFAS-106, "Accounting for Postretirement Benefits Other than Pensions", in 1992. The Company 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 as the benefit becomes due.

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

	(Millions)	
	1995	1994
Accumulated postretirement benefit obligation:		
Retired employees	$(68.3)	$(42.4)
Active employees	(14.0)	(26.4)
	$(82.3)	$(68.8)
Less—Plan assets at fair value	0.0	0.0
Accumulated postretirement benefit obligation (in excess of) less than fair value of assets	(82.3)	(68.8)
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	10.3	0.8
Prior service cost not yet recognized in net periodic pension cost	7.5	5.6
Unrecognized net obligation at December 31	45.1	47.9
Accrued postretirement benefit cost	$(19.4)	$(14.5)

Net periodic postretirement benefit cost included the following components:

	(Millions)	
	1995	1994
Service cost—benefits attributed to the period	$ 0.7	$ 0.9
Interest cost on accumulated postretirement benefit obligation	5.5	4.9
Actual return on plan assets	0.0	0.0
Net amortization and deferral	2.9	3.4
Net periodic postretirement benefit cost	$ 9.1	$ 9.2

The Accumulated Postretirement Benefit Obligation at December 31, 1995 and 1994 assumed discount rates of 6.75% and 8.50%, respectively, and long-term rate of increase in future compensation levels of 5.00% and 6.00%, respectively.

SFAS-112, "Employers' Accounting for Postemployment Benefits", was adopted by the Company in 1994. SFAS-112 requires the Company to recognize the obligation to provide postemployment benefits to former or inactive employees after employment but before retirement. The additional postemployment obligation at the time of the accounting change was approximately $11 million and is being deferred on the balance sheet.

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NOTE 4

Departmental Financial Information

The Company's records are maintained by operating departments, in accordance with PSC accounting policies. 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 Consolidated Statement of Income.

(Thousands of Dollars)	1995	1994	1993
Electric			
Operating Information			
Operating revenues	$ 722,465	$ 674,753	$ 655,316
Operating expenses, excluding provision for income taxes	518,762	489,982	486,951
Pretax operating income	203,703	184,771	168,365
Provision for income taxes	59,500	52,842	43,845
Net operating income	$ 144,203	$ 131,929	$ 124,520
Other Information			
Depreciation and amortization	$ 78,812	$ 75,211	$ 72,326
Nuclear fuel amortization	$ 17,982	$ 18,048	$ 18,861
Capital expenditures	$ 93,634	$ 93,477	$ 112,022
Investment Information			
Identifiable assets (a)	$2,228,056	$1,920,504	$1,978,009
Gas			
Operating Information			
Operating revenues	$293,863	$326,061	$293,708
Operating expenses, excluding provision for income taxes	275,978	294,575	265,510
Pretax operating income	17,885	31,486	28,198
Provision for income taxes	6,715	8,403	5,485
Net operating income	$ 11,170	$ 23,083	$ 22,713
Other Information			
Depreciation and amortization	$ 12,781	$ 12,250	$ 11,815
Capital expenditures	$ 15,913	$ 23,742	$ 27,385
Investment Information			
Identifiable assets (a)	$477,758	$487,333	$491,563

(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 Consolidated 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 as estimated by Niagara Mohawk Power Corporation	850	1,143
RG&E's share—megawatts	204	160
—percent	24	14
Year of completion	1980	1988
	Millions of Dollars at December 31, 1995	
Plant In Service Balance	$98.6	$880.0
Accumulated Provision For Depreciation	$36.8	$457.8
Plant Under Construction	$ 0.4	$ 3.2

The Plant in Service and Accumulated Provision for Depreciation balances for Nine Mile Point Nuclear Unit No. 2 shown above include 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 of Dollars) Principal Amount December 31 1995	1994
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
8⅜	CC	Sept. 15, 2007	49,000	50,000
6½	EE (a)	Aug. 1, 2009	10,000	10,000
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	30,000
7.15	(b) (c)	Feb. 10, 2003	39,000	39,000
7.13	(b) (c)	Mar. 3, 2003	1,000	1,000
7.64	(c)	Mar. 15, 2023	33,000	33,000
7.66	(c)	Mar. 15, 2023	5,000	5,000
7.67	(c)	Mar. 15, 2023	12,000	12,000
6.375	(b) (c)	July 30, 2003	40,000	40,000
7.45	(c)	July 30, 2023	40,000	40,000
			643,000	644,000
Net bond discount			(668)	(722)
Less: Due within one year			18,000	—
Total			$624,332	$643,278

(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 the 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 maturities 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 1995 and 1994 requirements were met by certification of additional property.

On February 15, 1994 the Company redeemed $2.75 million principal amount of its First Mortgage 10.95% Bonds, Series FF, pursuant to a sinking fund provision. On June 15, 1994 the Company redeemed all of its outstanding $15 million principal amount of First Mortgage 13⅞% Bonds, Series JJ, due June 15, 1999. Of the $15 million total, $2.5 million was redeemed through a mandatory sinking fund provision, and the remaining $12.5 million was redeemed at the Company's option.

(Note 6 continued on page 34)

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There are no sinking fund requirements for the next five years. Bond maturities for the next five years are:

	(Thousands of Dollars)				
	1996	1997	1998	1999	2000
Series V	$18,000				
Series W		$20,000			
Series X			$30,000		
Series Y				$30,000	
7% Series					$30,000
	$18,000	$20,000	$30,000	$30,000	$30,000

Promissory Notes

Issued	Due	(Thousands of Dollars) December 31 1995	1994
November 15, 1984 (d)	October 1, 2014	$51,700	$51,700
December 5, 1985 (e)	November 15, 2015	40,200	40,200
Total		$91,900	$91,900

(d) 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, 1997. 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 3.68% for 1995, 2.82% for 1994 and 2.19% for 1993. The interest rate will be adjusted monthly unless converted to a fixed rate.

(e) 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, 1998. The annual interest rate was adjusted to 2.75% effective November 15, 1993, to 4.40% effective November 15, 1994 and to 3.75% effective November 15, 1995. 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 1995 of 6.69% 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 $780 million at December 31, 1995.

Based on an estimated borrowing rate at year-end 1994 of 8.62% for long-term debt with similar terms and average maturities (13 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $667 million at December 31, 1994.

NOTE 7

Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,220,000*
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, 1995	(Thousands) December 31 1995	1994	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, 1995	(Thousands) December 31 1995	1994	Optional Redemption (per share)
8.25	R	—	$ —	$ —	Not applicable
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
6.60	V	250,000	25,000	25,000	Not Before 3/1/04+
Total		550,000	$55,000	$55,000	

+Thereafter at $100.00

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. The Company redeemed the remaining 180,000 shares on March 1, 1994 at $100 per share. Capital stock expense of $1.4 million was charged against retained earnings in connection with the redemption of the Series R Preferred Stock in 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.

Series V. The Series V is subject to a mandatory sinking fund sufficient to redeem on each March 1 beginning in 2004 to and including 2008, 12,500 shares at $100 per share and on March 1, 2009, the balance of the outstanding shares. The Company has the option to redeem up to an additional 12,500 shares on the same terms and dates as applicable to the mandatory sinking fund.

Based on an estimated dividend rate at year-end 1995 of 5.90% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (6.66 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $59 million at December 31, 1995.

Based on an estimated dividend rate at year-end 1994 of 7.50% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (8.65 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $54 million at December 31, 1994.

NOTE 8

Common Stock

At December 31, 1995, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 38,453,163 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 1,369,062 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 185,743 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

Capital stock expense increased in 1993 primarily due to expenses associated with the public sale of Common Stock. Redemption of the Company's 8.25% Preferred Stock, Series R, decreased capital stock expense by $0.9 million in 1993 and $1.4 million in 1994.

Common Stock

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1993		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
Decrease (Increase) in Capital Stock Expense			(615)
Balance, December 31, 1993		36,911,265	$652,172
Automatic Dividend Reinvestment and Stock Purchase Plan	$20.313–$25.088	644,478	14,797
Savings Plus Plan	$20.313–$24.875	114,220	2,572
Decrease (Increase) in Capital Stock Expense			1,028
Balance, December 31, 1994		37,669,963	$670,569
Automatic Dividend Reinvestment and Stock Purchase Plan	$20.288–$23.625	680,073	14,803
Savings Plus Plan	$20.438–$23.875	103,127	2,271
Decrease (Increase) in Capital Stock Expense			(125)
Balance, December 31, 1995		38,453,163	$687,518

NOTE 9

Short-Term Debt

At December 31, 1995, the Company had no short-term debt outstanding. On December 31, 1994, the Company had short-term debt outstanding of $51.6 million. The weighted average interest rate on short-term debt borrowed during 1995 was 6.14%. For 1994, the weighted average interest rate on short-term debt outstanding at year end was 6.01% and was 4.50% for borrowings during the year.

The Company has a $90 million revolving credit agreement for a term of three years. In December of 1995 the Company was granted a one-year extension of the commitment termination date to December 31, 1998. Commitment fees related to this facility amounted to $165,000 in 1995 and $169,000 per year in 1994 and 1993.

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, 1995, the Company would be able to incur $63.4 million of additional unsecured debt under this provision. The Company has unsecured lines of credit totaling $92 million available from several banks, at their discretion. The aggregate borrowings outstanding at any time under these lines of credit cannot exceed the 15% Charter limitation.

In order to be able to use its $90 million 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. In addition, the Company has a Loan and Security Agreement to provide for borrowings up to $20 million for the exclusive purpose of financing Federal Energy Regulatory Commission Order 636 transition costs (636 Notes) and up to $20 million as needed from time to time for other working capital needs. Borrowings under this agreement, which can be renewed annually, are secured by a lien on the Company's accounts receivable.

At December 31, 1995, borrowings outstanding were $13.9 million of 636 Notes (recorded on the Balance Sheet as a deferred credit).

NOTE 10 *Commitments and Other Matters*

Capital Expenditures.

The Company's 1996 construction expenditures program is currently estimated at $150 million, including $51 million related to replacement of the steam generators at the Ginna Nuclear Plant. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nuclear-Related Matters.

Decommissioning Trust. The Company is 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.

Under accounting procedures approved by the PSC, the Company has collected decommissioning costs of approximately $78.9 million through December 31, 1995. In connection with the Company's rate settlement completed in August 1993, the PSC approved the collection during the rate year ending June 30, 1996 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 $169.5 million for Ginna and $38.6 million for the Company's 14% share of Nine Mile Two (January 1995 dollars). This estimate is based principally on the application of a Nuclear Regulatory Commission (NRC) formula to determine minimum funding with an additional allowance for removal of non-contaminated structures. 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 completed a site specific cost analysis of decommissioning at Ginna and incorporated the results of this study in its July 1995 rate filing with the PSC. Based on the site specific study the estimated decommissioning cost increased to $296.3 million (May 1995 dollars). The Company has received Niagara Mohawk's estimate of a site specific cost estimate for Nine Mile Two which indicates the Company's share of such costs could be as much as $113 million. This estimate is currently under review by the Company and the other co-tenants and the staff of the PSC. The Company cannot predict the timing or extent to which any additional estimates will be recognized in rates.

The NRC requires reactor licensees to submit funding plans that establish minimum NRC external funding levels for reactor decommissioning. The Company's plan, filed in 1990, consists of an external decommissioning trust fund covering both its Ginna Plant and its Nine Mile Two share. Since 1990, the Company has contributed $54.4 million to this fund and, including realized and unrealized investment returns, the fund has a balance of $71.5 million as of December 31, 1995. The amount attributed to the allowance for removal of non-contaminated structures is being held in an internal reserve. The internal reserve balance as of December 31, 1995 is $24.4 million.

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 further increase funding. The Company continues to monitor these activities and although an increase in funding levels is likely, the Company cannot predict what regulatory actions the NRC may ultimately take.

The Staff of the Securities and Exchange Commission and the Financial Accounting Standards Board are currently studying the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. If current accounting practices for such costs were changed, the annual provisions for decommissioning costs could increase, the estimated cost for decommissioning could be reclassified as a liability rather than as accumulated depreciation, the liability accounts and corresponding plant asset carrying accounts could be increased and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

(Note 10 continued on page 38)

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If annual decommissioning costs increased, the Company would expect to defer the effects of such costs pending disposition by the PSC.

Uranium Enrichment Decontamination and Decommissioning Fund. As part of the National Energy Act (Energy 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 $22.1 million, excluding inflation and interest. The first three installments aggregating approximately $6.2 million have been paid through 1995. A liability has been recognized on the financial statements along with a corresponding regulatory asset. For the two facilities the Company's liability at December 31, 1995 is $17.5 million ($15.8 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. The Company believes that the full amount of the assessment will be recoverable in rates as described in the Energy Act.

Nuclear Fuel Disposal Costs. The Nuclear Waste Policy Act (Nuclear Waste 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 an 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 Nuclear Waste 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 $75.1 million at December 31, 1995. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Nuclear Waste Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.001) per KWH of nuclear energy generated and sold. This charge (approximately $2.7 million per year) 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.

There are presently no facilities in operation in the United States available for the reprocessing of spent nuclear fuel from utility companies. In the Company's determination of nuclear fuel costs it has taken into account that nuclear fuel would not be reprocessed and has provided for disposal costs in accordance with the Nuclear Waste Act. The Company has completed a conceptual study of alternatives to increase the capacity for the interim storage of spent nuclear fuel at the Ginna Plant. The preferred alternative, based on cost and safety criteria, is to install high-capacity spent fuel racks in the existing area of the spent fuel pool. The additional storage capacity, scheduled to be implemented prior to September 2000, would allow interim storage of all spent fuel discharged from the Ginna Plant through the end of its Operating License in the year 2009.

Spent Nuclear Fuel Litigation. The Nuclear Waste Act obligates the DOE to accept for disposal spent nuclear fuel (SNF) starting in 1998. Since the mid-1980s the Company and other nuclear plant owners and operators have paid substantial fees to the DOE to fund its obligations under the Nuclear Waste Act. DOE has indicated that it may not be in a position to accept SNF in 1998. On June 20, 1994, Northern States Power Company and other owners and operators of nuclear power plants filed suit against DOE and the U.S. in the U.S. Court of Appeals for the District of Columbia Circuit asking for a declaration that DOE is not acting in accordance with law, seeking orders directing DOE to submit to the Court a description of and progress reports on a program to begin acceptance of SNF by 1998, and requesting other relief, including an order allowing petitioners to pay fees into an escrow fund rather than to DOE. The Company has joined Northern States and the other petitioners in this litigation. Petitioners initial and reply briefs were filed in October and November, 1995, respectively and oral argument was completed in January, 1996. A decision is expected in the second quarter of 1996.

Nuclear Fuel Enrichment Services. The Company has two contracts for enrichment services, one with the United States Enrichment Corporation (USEC), formerly part of the DOE, for nuclear fuel enrichment services which assures provision for 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, 2004 and 2005. Additionally, the Company will accept only 70% of its required enrichment services from USEC in 1996 through 1999. A second enrichment service contract has been placed with Urenco, Inc., with enrichment facilities in Europe, to cover 30% of the Company's requirements from 1996 through 1999, and 100% of requirements in 2000 and 2001. The Company plans to meet its enrichment requirements for years beyond those already committed by making further arrangements with USEC, Urenco or by contracting with third parties. The estimated cost of enrichment services utilized every 18 months for the next seven years is expected to range from $10 million to $13 million.

Insurance Program. The Price-Anderson Act establishes a federal program insuring against public liability in the event of a nuclear accident at a licensed U.S. reactor. 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 $79.3 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 a surcharge for New York State premium taxes. The Company's interests in two nuclear units could thus expose it to a potential liability for each accident of $90.4 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.

Claims alleging radiation-induced injuries to workers at nuclear reactor sites 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 $3.0 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. 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 $3.8 million and $17.2 million in the event of losses under the replacement power and property damage coverages, respectively.

Litigation with Co-Generator.

Under federal and New York State laws and regulations, the Company is required to purchase the electrical output of unregulated cogeneration facilities which meet certain criteria (Qualifying Facilities). Under these statutes, a utility is required to pay for electricity from Qualifying Facilities at a rate that equals the cost to the utility of power it would otherwise produce itself or purchase from other sources (Avoided Cost). With the exception of one contract which the Company was compelled by regulators to enter into with Kamine/Besicorp Allegany L.P. (Kamine) for approximately 55 megawatts of capacity, the Company has no long-term obligations to purchase energy from Qualifying Facilities.

Under State law and regulatory requirements in effect at the time the contract with Kamine was negotiated, the Company was required to agree to pay Kamine a price for power that is substantially greater than the Company's own cost of production and other purchases. Since that time the State law mandating a minimum price higher than the Company's own costs has been repealed and PSC estimates of future costs on which the contract was based have declined dramatically.

(Note 10 continued on page 40)

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In September 1994, the Company commenced a lawsuit in New York State Supreme Court, Monroe County, seeking to void or, alternatively, to reform a Power Purchase Agreement with Kamine for the purchase of the electrical output of a cogeneration facility in the Town of Hume, Allegany County, New York, for a term of 25 years. The contract was negotiated pursuant to the specific pricing requirement of a State statute that was later repealed, as well as estimates of Avoided Costs by the PSC that subsequently were drastically reduced. As a result, the contract requires the Company to pay prices for Kamine's electrical output that dramatically exceed current Avoided Costs and current projections of Avoided Costs. The Company's lawsuit seeks to avoid payments to Kamine that exceed actual and currently projected Avoided Costs. Kamine answered the Company's complaint, seeking to force the Company to take and pay for power at the higher rates called for in the contract and claiming damages in an unspecified amount alleged to have been caused by the Company's conduct. The Company received test generation from the Kamine facility during the last quarter of 1994. Kamine contends that the facility went into commercial operation in December 1994 and that the Company is obligated to pay the full contract rate for it. The Company disputes this contention and refuses to pay the full contract rate. During 1995 Kamine filed a motion for summary judgement dismissing the Company's complaint and directing it to perform the Power Purchase Agreement. The court denied that motion and Kamine appealed. After argument of that appeal Kamine filed for protection under the Bankruptcy laws and sent to the Appellate Division a notice that all further proceedings were stayed. The Company is unable to predict the ultimate outcome of this litigation.

In addition, Kamine has filed a related complaint in the United States District Court for the Western District of New York alleging that the conduct which is the subject of the State court action violates the federal antitrust laws. The complaint seeks treble damages in the amount of $420,000,000, as well as preliminary and permanent injunctions. Subsequently, Kamine filed a motion for a preliminary injunction in the federal action to enjoin the Company from refusing to accept and purchase electric power from Kamine and enjoining the Company from terminating during the pendency of this lawsuit its performance under the contract. In November, 1995, the Court issued a decision denying Kamine's motion for a preliminary injunction, finding, among other things, that Kamine had not established the necessary likelihood of success on the merits of its action. Kamine filed a notice of appeal from that decision but has subsequently announced that it is withdrawing that appeal. The Company is unable to predict the ultimate outcome of this litigation.

During 1995 the PSC invited the Company to file a petition requesting, among other things, that the Commission commence an investigation to determine whether at the time of claimed commercial operation the Hume plant was a cogeneration facility under New York law as required by the Power Purchase Agreement. The Company filed such a petition and Kamine filed papers in opposition. The Company is unable to predict the ultimate outcome of this proceeding.

Also during 1995 Kamine filed a petition before the FERC to waive certain requirements for federal Qualified Facility status for 1994. The Company and the PSC filed in opposition to the request. Subsequently FERC issued an order granting the waiver request and the Company has filed a motion for reconsideration.

In November 1995 Kamine filed in Newark, New Jersey for protection under the Bankruptcy laws and filed a complaint in an adversary proceeding seeking, among other things, specific performance of the Power Purchase Agreement. Kamine filed a motion to compel the Company to pay under its view of the terms of the Power Purchase Agreement during the pendency of the Adversary Proceeding. After hearing, the Bankruptcy Court denied that motion. The Court also denied various motions made by the Company to change the venue of the proceedings to New York State and to lift the automatic stay of the pending New York State Action. The Company has filed a notice of appeal to the District Court for the denial of its motions. The PSC has filed a motion to lift the stay to permit it to proceed with its investigation of the Hume facility under New York State Law. General Electric Credit Corporation which had provided financing to the Hume project, has intervened in the Adversary Proceeding as a plaintiff. The Company has filed an answer with affirmative defenses and counterclaims in the Adversary Proceeding. The counterclaims seek, among other things, the relief sought in the New York State Court action described above. The parties are now engaged in discovery in connection with the Adversary Proceeding.

The existence of mandated high priced independent power purchase agreements is a significant problem throughout the State of New York and there are various efforts by State officials to resolve the problem. The Company continues to work to resolve this particular dispute in a fashion that is fair and equitable to all parties, however, we will continue to take aggressive action on behalf of customers and the Company to assure that their interests are respected in any resolution. The Company is unable to predict the ultimate outcome of these efforts on the legal proceedings.

Environmental Matters.

The following tables list various sites where past waste handling and disposal has or may have occurred that are discussed below:

Site Name	Location	Estimated Company Cost
Table I—*Company-Owned Sites:*		
West Station	Rochester, NY	Ultimate costs have not been determined. The Company has incurred aggregate costs for these sites through December 31, 1995 of $2.4 million.
East Station	Rochester, NY	
Front Street	Rochester, NY	
Brewer Street	Rochester, NY	
Brooks Avenue	Rochester, NY	
Canandaigua	Canandaigua, NY	
Table II—*Superfund and Other Sites:*		
Quanta Resources*	Syracuse, NY	Ultimate costs have not been determined. The Company has incurred aggregate costs for these sites through December 31, 1995 of $1.0 million.
Frontier Chemical Pendleton*	Pendleton, NY	
Maxey Flats*	Morehead, KY	
Mexico Milk	Mexico, NY	
Byron Barrel and Drum	Bergen, NY	
Fulton Terminals*	Oswego, NY	
PAS of Oswego*	Oswego, NY	

*Orders on consent signed.

Company-Owned Waste Site Activities: As part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and/or Remediation (SIR) efforts at six Company-owned sites where past waste handling and disposal may have occurred. Remediation activities at three of these sites are in various stages of planning or completion and the Company is conducting a program to restore, as necessary to meet environmental standards, the other three sites. The Company has recorded a total liability of approximately $11 million, $8 million of which it anticipates spending on SIR efforts at the six Company-owned sites listed in Table I above where past waste handling and disposal may have occurred. Concurrently, the Company recorded a similar increase in its Regulatory Assets. Approximately $4.5 million has been provided for in rates through June 1996 ($1.5 million annually) 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 mid-1995, the New York State Department of Environmental Conservation (NYSDEC) developed a listing of sites called "The Hazardous Substance Site Inventory." Under current New York State law, unless a site, which is determined to pose a public health or environmental risk, contains hazardous wastes, State "Superfund" monies cannot be used to assist in the clean-up. The State wanted to have some sense of the scale of this problem before the legislature considered other avenues of legal and financial redress than those currently available. The NYSDEC's "Hazardous Substance Waste Disposal Site Study" was developed to assess the number of and cost to remediate sites where hazardous chemicals, but not hazardous wastes are present. Of the six Company-owned sites listed in Table I above, three are listed in this inventory. These are East Station, Front Street and Brooks Avenue. In addition to these three sites, the inventory includes Ambrose Yard and Lindberg Heat Treating. The Company does not believe that additional SIR work for which the Company is responsible is required at either site, however the Company is unable to predict what action will be necessitated as a result of the listing.

The Company and its predecessors formerly owned and operated three manufactured gas facilities in the Rochester area. They are included in Table I. In September 1991, the Company initiated a

(Note 10 continued on page 42)

Electric Corporation

(continued from page 41)

study of subsurface conditions in the vicinity of retired facilities at its West Station manufactured gas property and has since commenced the removal of soils containing hazardous substances in order to minimize any potential long-term exposure risks. Cleanup efforts were temporarily suspended while the Company investigated more cost effective remedial technologies. Cleanup activities resumed in October 1995 and are scheduled to be concluded in April 1996. At the second of the three manufactured gas plant sites known as East Station, an interim remedial action was undertaken in late 1993. Ground water monitoring wells were also installed to assess the quality of the ground water at this location. The Company has informed the NYSDEC of the results of the samples taken. These results may indicate that some further action may be required.

At the third Rochester area property owned by the Company (Front Street) where gas manufacturing took place, a boring placed in the Fall of 1988 for a sewer system project showed a layer containing a black viscous material. The study of the layer 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 since the report's submittal. The Company is formulating plans for long-term management of the site.

Another property owned by the Company where gas manufacturing took place is located in Canandaigua, New York. Limited investigative work performed there during the Summer of 1995 has shown evidence of both the former gas manufacturing operations and leakage from fuel tanks. The NYSDEC was informed; the fuel tanks removed; and additional work planned for 1996. The SIR costs associated with these actions are included in Table I. The NYSDEC has not taken any action against the Company as a result of these findings.

On another portion of the Company's property in the Rochester area (Brewer Street), 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 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 an existing 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 most recent 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.

The NYSDEC did not include the site in its hazardous substance inventory, presumably pending negotiations with the County to pursue appropriate closure of the County's former retention pond area. The Company and the County continue to negotiate to resolve the issue. The Company is unable to assess the outcome of the negotiations or the implications of the NYSDEC's attempts to secure proper closure.

Monitoring wells installed at another Company facility (Brooks Avenue) in 1989 revealed that an undetermined amount of leaded gasoline had reached the ground water. 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. It is estimated that further investigative work into this problem may cost up to $100,000. In December 1994, the NYSDEC granted a permit for the storage of hazardous wastes at this location. Conditions of the permit require additional investigation and corrective action of the hazardous constituents at the site. While the cost of corrective actions cannot be determined until investigations are completed, preliminary estimates are in the range of $160-180 thousand.

Superfund and Other Sites. The Company has been or may be associated as a potentially responsible party (PRP) at seven sites not owned by it. The Company has signed orders on consent for five of these sites and recorded estimated liabilities totaling approximately $3 million.

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 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 and has signed a consent order to that effect. The Company, in the lower tier of PRPs, paid its $27,500 share of such cost. Although 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 determine the cost to design and conduct at the site any remedial measures which federal or State authorities may require, the Company does not expect its costs to exceed $250,000.

On May 21, 1993, the Company was notified by NYSDEC that it was considered a PRP for the Frontier Chemical Pendleton Superfund Site located in Pendleton, NY. The Company has signed, along with other participating parties, an Administrative Order on Consent with NYSDEC. The Order on Consent obligates the parties to implement a work plan and remediate the site. The PRPs have negotiated a work plan for site remediation and have retained a consulting firm to implement the work plan. 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. Subsequent work has indicated that the final cost is likely to be lower.

The Company is involved in the investigation and cleanup of the Maxey Flats Nuclear Disposal Site in Morehead, Kentucky and has signed various consent orders to that effect. The Company has contributed to a study of the site and estimates that its share of the cost of investigation and remediation would approximate $205,000.

The Company has been named as a PRP at three other sites and has been associated with another site for which the Company's share of total projected costs is not expected to exceed $120,000. Actual Company expenditures for these sites are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several.

Federal Clean Air Act Amendments. The Company is developing strategies responsive to the federal Clean Air Act Amendments of 1990 (Amendments) which will primarily affect air emissions from the Company's fossil-fueled electric generating facilities. A range of capital costs between $15 million and $25 million has been estimated for the implementation of several potential scenarios which would enable the Company to meet the foreseeable NOx and sulphur dioxide requirements of the Amendments. These capital costs would be incurred between 1996 and 2000. The Company estimates that it could also incur up to $2.1 million of additional annual operating expenses, excluding fuel, to comply with the Amendments.

Gas Cost Recovery.

FERC 636 Transition Costs. As a result of the restructuring of the gas transportation industry by the FERC pursuant to Order No. 636 and related decisions, there have been and will be a number of changes in this aspect of the Company's business over the next several years. These changes will require the Company to pay a share of certain transition costs incurred by the pipelines as a result

(Note 10 continued on page 44)

(continued from page 43)

of the FERC-ordered industry restructuring. The final amounts of such transition costs are subject to continuing negotiations with several pipelines and ongoing pipeline filings requiring FERC approval. The Company, as a customer, has estimated total costs of about $63.2 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 $36.2 million of these costs were paid to various suppliers, of which about $22.2 million has been included in purchased gas costs. At year-end, $41.0 million remains deferred for future collection from customers. The Company entered into a $20 million credit agreement with a domestic bank to provide funds for the Company's transition cost liability to CNG Transmission Corporation (CNG). At December 31, 1995 the Company had $13.9 million of borrowings outstanding under the credit agreement. The Company is collecting those costs through the Gas Clause Adjustment in its rates.

The Company is committed to transportation capacity on the Empire State Pipeline (Empire) as well as to upstream pipeline transportation and storage services. The Company also has contractual obligations with CNG and upstream pipelines whereby the Company is subject to charges for transportation and storage services for a period extending to the year 2001. The combined CNG and Empire transportation capacity exceeds the Company's current requirements. This temporary excess has occurred largely due to the Company's initiatives to diversify its supply of gas and the industry changes and increasing competition resulting from the implementation of FERC Order 636.

1995 Gas Settlement. The Company's purchased gas expense charged to customers was higher during the 1994-95 heating season compared with prior years, generating substantial customer concern. The action the Company took to reduce rates included refunding the weather normalization adjustment charged to customers in January 1995 and discontinuation of those charges through the remainder of the heating season ending in May 1995. The weather normalization adjustment provides for recovery of fixed charges by producing higher unit rates when the weather is warm and usage is low. Conversely, it would provide lower unit rates during colder periods of high usage.

In December 1994, the PSC instituted a proceeding to review the Company's practices regarding acquisition of pipeline capacity, the deferred costs of the capacity and the Company's recovery of those costs.

In April 1995, the PSC issued a Department of Public Service staff report on the Company's 1994-1995 billing practices and procedures which presented recommendations regarding changes in the Company's natural gas purchasing, billing, meter reading and communication activities.

On August 17, 1995, the Company announced that a negotiated settlement had been reached with the Staff of the PSC and other parties which would resolve various PSC proceedings affecting the Company's gas costs. On October 18, 1995, the PSC approved, effective November 1, 1995, (1) the settlement discussed below, (2) elimination of the weather normalization clause in gas rates and (3) the Company's plan for improving its gas billing procedures (the 1995 Gas Settlement). This settlement affects the rate treatment of various gas costs through October 31, 1998.

Highlights of the 1995 Gas Settlement are:

- The Company will forego, for three years, gas rate increases exclusive of the cost of natural gas and certain cost increases imposed by interstate pipelines.
- The Company has agreed not to charge customers for pipeline capacity costs in 1996, 1997 and 1998 of $22.5 million, $24.5 million, and $27.2 million, respectively. Under FERC rules, the Company may sell its excess transportation capacity in the market. The value of those sales can be used to offset the capacity costs that will not be charged to customers. These amounts that the Company will not be permitted to charge are subject to increase in the event of major increases in the overall cost of pipeline capacity during these years. The foregoing amounts include the cost of capacity to be purchased by replacement shippers. As discussed below, a substantial portion of this capacity is expected to be released and sold in the market pursuant to a marketing agreement with CNG, a supply agreement with MidCon Gas Services Corporation (MGSC), and other individual agreements.
- The Company agreed to write off excess gas pipeline capacity costs incurred through 1995.
- As part of a separate decision, the PSC agreed with the Company's request to eliminate the weather

normalization clause effective November 1, 1995. The weather normalization clause had adjusted gas customer billing for abnormal weather variations.

The economic effect of the 1995 Gas Settlement on the Company's 1995 results of operations may be summarized as follows:

Description	Millions of Dollars (Pretax)	Earnings per Share Effect
Elimination of weather normalization charges	$ 5.8	$(.10)
Foregone gas rate increase scheduled for July 1, 1995	2.8	(.04)
Foregone gas pipeline capacity costs for 1995	8.8	(.15)
Gas pipeline capacity and other costs which were written off in October 1995	23.2	(.40)
Provision for retroactive pipeline charges pending before FERC	3.6	(.06)
Total	$44.2	$(.75)

Under provisions of the 1995 Gas Settlement, the Company faces an economic risk of remarketing $74.2 million of excess gas capacity through 1998. The Company has entered into a marketing agreement with CNG that is expected to result in the release of approximately $29 million of this capacity through the period. CNG will assist the Company in obtaining permanent replacement customers for transportation capacity the Company will not require. To help manage the balance of the excess capacity costs at risk, the Company has retained MGSC which will work with the Company to identify and implement opportunities for temporary and permanent release of surplus pipeline capacity and advise in the management of the Company's gas supply, transportation and storage assets consistent with the goal of providing reliable service and reducing the cost of gas.

The ultimate financial impact of the 1995 Gas Settlement on the Company's business in 1996 and subsequent years will be largely determined by the degree of success achieved by the Company in remarketing its excess gas capacity and in controlling its local gas distribution costs.

Purchased Gas Undercharges.

In March 1994 the PSC approved a December 1993 settlement among the Company, PSC Staff and another party regarding the Company's accounting for certain gas purchases for the period August 1990-August 1992 which resulted in undercharges to gas customers of approximately $7.5 million. The Company wrote off $2.0 million of the undercharges as of December 31, 1993, reducing 1993 earnings by four cents per share, net of tax. In April 1994, the Company wrote off an additional one cent per share, net of tax. Under the 1993 settlement, the Company was to collect $2.6 million from customers over a three-year period. Due to rate increase limitations established in the Company's 1993 Rate Agreement and certain provisions under the 1995 Gas Settlement; however, the Company is precluded from collecting the $2.6 million and accordingly, this amount was written off in 1995 and is reflected in Other Deductions on the Statement of Income.

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 is the year in which the plant was placed in service.

The Company filed a protest of the IRS adjustments to its 1987-88 tax liability. 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.

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The IRS also completed in 1994 its audit of the Company's federal income tax returns for 1989 and 1990, which has resulted in a proposed refund of $600,000. Since this refund arises from the contentious issues from the prior audit, the Company filed a protest with the IRS.

Regulatory and Strandable Assets.

The Company has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are then recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by Statement of Financial Accounting Standards No. 71 (SFAS-71). These deferred costs are shown as Regulatory Assets on the Company's Balance Sheet. Such cost deferral is appropriate under traditional regulated cost-of-service rate setting, where all prudently incurred costs are recovered through rates. In a purely competitive pricing environment, such costs might not have been incurred and could not have been deferred. Accordingly, if the Company's rate setting was changed from a cost-of-service approach, and it was no longer allowed to defer these costs under SFAS-71, these assets would be adjusted for any impairment to recovery (see discussion under Financial Accounting Standards No.121). In certain cases, the entire amount could be written off.

Below is a summarization of the Regulatory Assets as of December 31, 1995.

	Millions of Dollars
Income Taxes	$188.6
Uranium Enrichment Decommissioning Deferral	18.7
Deferred Ice Storm Charges	16.6
FERC 636 Transition Costs	41.0
Demand Side Management Costs Deferred	14.7
Other, net	31.6
Total—Regulatory Assets	$311.2

- Income Taxes: This amount represents the unrecovered portion of tax benefits from accelerated depreciation and other timing differences which were used to reduce tax expense in past years. The recovery of this deferral is anticipated over the remaining life of the related property when the effect of the past deductions reverses in future years.
- Deferred Ice Storm Charges: These costs result from the non-capital storm damage repair costs following the March 1991 ice storm. The recovery of these costs has been approved by the PSC through the year 2002.
- Uranium Enrichment Decommissioning Deferral: The Energy Policy Act of 1992 requires utilities to contribute such amounts based on the amount of uranium enriched by DOE for each utility. This amount is mandated to be paid to DOE over the next 13 years. The recovery of these costs is through the Company's fuel adjustment clause, over a comparable period.
- FERC 636 Transition Costs: These costs are payable to gas supply and pipeline companies which are passing various restructuring and other transition costs on to the Company, as ordered by FERC. The majority of these costs will be recovered through the Company's gas cost adjustment over the next three years.
- Demand Side Management Costs Deferred: These costs are Demand Side Management costs which relate to programs initiated to increase efficiency with which electricity is used. These costs are recoverable by the Company over the next five years.

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. Examples include purchase power contracts (e.g., the Kamine/Besicorp Allegany L.P. contract), or high cost generating assets. Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. The amount of potentially strandable assets at December 31, 1995 cannot be determined at this time, but could be significant.

Financial Accounting Standards No. 121.

In March 1995, the Financial Accounting Standards Board (FASB) issued Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" (SFAS-121). SFAS-121 amends SFAS-71 to require write-off of a regulatory asset or strandable asset if it is no longer probable that future revenues will cover the cost of the asset. SFAS-121 also requires a company to recognize a loss whenever events or circumstances occur which indicate that the carrying amount of an asset may not be fully recoverable. At December 31, 1995 the Company's regulatory assets totaled $311.2 million. At the current time, the Company believes its regulatory assets are probable of recovery, and, accordingly, the adoption of this accounting standard will not have a material impact on the financial position or results of operations of the Company.

Lease Agreements.

The Company leases several buildings for administrative offices and operating activities. The total lease expense charged to operations was $2.4 million in 1995. For the years 1996, 1997, 1998, 1999 and 2000 the estimated lease expense charged to operations will be $4.1 million, $4.1 million, $4 million, $2.3 million and $2.3 million, respectively. Commitments under capital leases were not significant to the accompanying financial statements.

REPORT OF INDEPENDENT ACCOUNTANTS

Price Waterhouse LLP

1900 Chase Square
Rochester, New York 14604-1984
January 19, 1996

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, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 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 3 to the financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 112, "Employers' Accounting for Postemployment Benefits" in 1994.

Price Waterhouse LLP

Report of Management

The management of Rochester Gas and Electric Corporation has prepared and is responsible for the consolidated 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 LLP, 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 LLP is presented on page 47.

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, 1995, 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

J. B. Stokes

J. Burt Stokes
Senior Vice President, Corporate Services and
Chief Financial Officer

January 19, 1996

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, 1995*	$270,518	$37,624	$ (387)	$ (2,253)	$(.05)
September 30, 1995	245,145	41,738	26,934	25,068	.65
June 30, 1995	219,546	29,454	14,861	12,995	.34
March 31, 1995	281,119	46,557	30,520	28,653	.75
December 31, 1994	$243,697	$42,249	$25,618	$23,751	$ .63
September 30, 1994**	229,982	41,007	4,912	3,046	.08
June 30, 1994	217,083	24,578	9,608	7,742	.20
March 31, 1994	310,052	47,178	34,237	32,467	.87
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

*Includes recognition of $28.7 million net-of-tax gas settlement adjustment.
**Includes recognition of $21.9 million net-of-tax pension plan curtailment.
***Includes recognition of $1.3 million net-of-tax pension plan curtailment.
****Includes recognition of $5.3 million net-of-tax pension plan curtailment.

Common Stock and Dividends

Earnings/Dividends	1995	1994	1993
Earnings per weighted average share	$1.69	$1.79	$2.00
Dividends paid per share	$1.80	$1.76	$1.72

Shares/Shareholders	1995	1994	1993
Number of shares (000's)			
Weighted average	38,113	37,327	35,599
Actual number at December 31	38,453	37,670	36,911
Number of shareholders at December 31	35,356	37,212	38,102

Tax Status of Cash Dividends.

Cash dividends paid in 1995, 1994 and 1993 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 Company believes that future dividend payments will need to be evaluated in the context of maintaining the financial strength necessary to operate in a more competitive and uncertain business environment. This will require consideration, among other things, of a dividend payout ratio that is lower over time, reevaluating assets and managing greater fluctuation in revenues. While the Company does not presently expect the impact of these factors to affect the Company's ability to pay dividends at the current rate, future dividends may be affected. 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 1996, the Company paid a cash dividend of $.45 per share on its Common Stock. The January 1996 dividend payment is equivalent to $1.80 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".

	1995	1994	1993
Common Stock—Price Range			
High			
1st quarter	23	26⅜	28⅜
2nd quarter	22⅝	25⅛	28
3rd quarter	24⅛	23¾	29¾
4th quarter	24⅛	21⅜	29¼
Low			
1st quarter	20⅜	23⅜	24⅛
2nd quarter	20⅛	20½	25½
3rd quarter	20	19¾	27⅜
4th quarter	22⅜	20⅛	24¾
At December 31	22⅝	20⅞	26¼

SELECTED FINANCIAL DATA

(Thousands of Dollars) Year Ended December 31	1995	1994	1993	1992	1991	1990
Consolidated Summary of Operations						
Operating Revenues						
Electric	$ 696,582	$ 658,148	$638,955	$608,267	$588,930	$551,[illegible]
Gas	293,863	326,061	293,708	261,724	235,728	236,496
	990,445	984,209	932,663	869,991	824,658	788,426
Electric sales to other utilities	25,883	16,605	16,361	25,541	28,612	42,465
Total Operating Revenues	1,016,328	1,000,814	949,024	895,532	853,270	830,891
Operating Expenses						
Fuel Expenses						
Electric fuels	44,190	44,961	45,871	48,376	65,105	76,420
Purchased electricity	54,167	37,002	31,563	29,706	27,683	34,264
Gas purchased for resale	167,762	194,390	166,884	141,291	129,779	132,512
Total Fuel Expenses	266,119	276,353	244,318	219,373	222,567	243,196
Operating Revenues Less Fuel Expenses	750,209	724,461	704,706	676,159	630,703	587,695
Other Operating Expenses						
Operations excluding fuel expenses	253,907	235,896	235,381	226,624	208,440	194,594
Maintenance	49,226	55,069	61,693	62,720	65,415	62,391
Depreciation and Amortization	91,593	87,461	84,177	85,028	84,181	77,767
Taxes—local, state and other	133,895	129,778	126,892	124,252	113,649	101,035
Federal income tax—current	65,368	35,658	33,453	36,101	28,766	20,661
—deferred	847	25,587	15,877	7,490	5,493	13,829
Total Other Operating Expenses	594,836	569,449	557,473	542,215	505,944	470,277
Operating Income	155,373	155,012	147,233	133,944	124,759	117,418
Other Income and Deductions						
Allowance for other funds used during construction	585	396	153	164	675	2,689
Federal income tax	16,948	16,259	9,827	4,195	4,580	2,4[illegible]
Regulatory disallowances	(26,866)	(600)	(1,953)	(8,215)	(10,000)	[illegible]
Pension plan curtailment	—	(33,679)	(8,179)	—	—	—
Other, net	(14,931)	(4,853)	(7,074)	6,155	6,078	4,062
Total Other Income and (Deductions)	(24,264)	(22,477)	(7,226)	2,299	1,333	9,210
Interest Charges						
Long term debt	53,026	53,606	56,451	60,810	63,918	64,873
Short term debt	398	1,808	1,487	1,950	2,623	1,070
Other, net	8,658	4,758	5,220	5,228	4,459	3,523
Allowance for borrowed funds used during construction	(2,901)	(2,012)	(1,714)	(2,184)	(2,905)	(2,719)
Total Interest Charges	59,181	58,160	61,444	65,804	68,095	66,747
Net Income	71,928	74,375	78,563	70,439	57,997	59,881
Dividends on Preferred Stock at Required Rates	7,465	7,369	7,300	8,290	6,963	6,025
Earnings Applicable to Common Stock	$ 64,463	$ 67,006	$ 71,263	$ 62,149	$ 51,034	$ 53,856
Weighted Average Number of Shares Outstanding in Each Period (000's)	38,113	37,327	35,599	33,258	31,794	31,293
Earnings per Common Share	$1.69	$1.79	$2.00	$1.86	$ 1.60	$ 1.72
Cash Dividends Declared per Common Share	$1.80	$1.77	$1.73	$1.69	$1.635	$1.575

Condensed Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1995	1994	1993	1992	1991	1990
Assets						
Utility Plant	$3,068,103	$2,981,151	$2,890,799	$2,798,581	$2,706,554	$2,310,294
Less: Accumulated depreciation and amortization	1,518,878	1,423,098	1,335,083	1,253,117	1,178,649	812,994
	1,549,225	1,558,053	1,555,716	1,545,464	1,527,905	1,497,300
Construction work in progress	121,725	128,860	112,750	83,834	76,848	82,663
Net utility plant	1,670,950	1,686,913	1,668,466	1,629,298	1,604,753	1,579,963
Current Assets	292,596	236,519	248,589	209,621	189,009	176,045
Investment in Empire	38,879	38,560	38,560	9,846	—	—
Deferred Debits and Regulatory Assets	472,968	504,204	507,769	200,676	160,034	108,451
Total Assets	$2,475,393	$2,466,196	$2,463,384	$2,049,441	$1,953,796	$1,864,459
Capitalization and Liabilities						
Capitalization						
Long-term debt	$ 716,232	$ 735,178	$ 747,631	$ 658,880	$ 672,322	$ 721,612
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	55,000	55,000	42,000	54,000	60,000	30,000
Common shareholders' equity:						
Common stock	687,518	670,569	652,172	591,532	529,339	516,388
Retained earnings	70,330	74,566	75,126	66,968	61,515	62,542
Total common shareholders' equity	757,848	745,135	727,298	658,500	590,854	578,930
Total Capitalization	1,596,080	1,602,313	1,583,929	1,438,380	1,390,176	1,397,542
Long Term Liabilities (Department of Energy)	90,887	87,826	89,804	94,602	63,626	59,989
Current Liabilities	182,338	181,327	234,530	267,276	267,601	183,720
Deferred Credits and Other Liabilities	606,088	594,730	555,121	249,183	232,393	223,208
Total Capitalization and Liabilities	$2,475,393	$2,466,196	$2,463,384	$2,049,441	$1,953,796	$1,864,459

Financial Data

At December 31	1995	1994	1993	1992	1991	1990
Capitalization Ratios (a) (percent)						
Long-term debt	47.4	48.2	49.4	48.2	50.6	53.6
Preferred stock	7.3	7.3	6.6	8.0	8.7	6.7
Common shareholders' equity	45.3	44.5	44.0	43.8	40.7	39.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$19.71	$19.78	$19.70	$18.92	$18.41	$18.42
Rate of Return on Average Common Equity (b) (percent)	8.37	8.92	10.25	9.94	8.60	9.29
Embedded Cost of Senior Capital (percent)						
Long-term debt	7.38	7.40	7.36	7.91	8.32	8.59
Preferred stock	6.26	6.26	6.69	6.98	6.97	6.72
Effective Federal Income Tax Rate (percent)	40.7	37.7	33.5	35.9	33.9	34.8
Depreciation Rate (percent)—Electric	2.76	2.69	2.62	2.69	3.05	3.33
—Gas	2.59	2.62	2.60	2.78	2.94	2.94
Interest Coverages						
Before federal income taxes (incld. AFUDC)	2.95	2.98	2.87	2.62	2.23	2.32
(excld. AFUDC)	2.90	2.94	2.84	2.58	2.18	2.25
After federal income taxes (incld. AFUDC)	2.16	2.24	2.24	2.04	1.82	1.86
(excld. AFUDC)	2.10	2.20	2.21	2.00	1.77	1.78
Interest Coverages Excluding Non-Recurring Items (c)						
Before federal income taxes (incld. AFUDC)	3.66	3.55	3.03	2.74	2.38	2.32
(excld. AFUDC)	3.61	3.51	3.00	2.70	2.33	2.25
After federal income taxes (incld. AFUDC)	2.62	2.61	2.35	2.12	1.91	1.86
(excld. AFUDC)	2.57	2.57	2.32	2.08	1.86	1.78

(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) The return on average common equity for 1995 excluding effects of the 1995 Gas Settlement is 12.10%. The rate of return on average common equity excluding effects of retirement enhancement programs recognized by the Company in 1994 and 1993 is 11.90% and 11.20%, respectively.
(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 1994 and 1993 exclude the effects of retirement enhancement programs recognized by the Company during each year and certain gas purchase under-charges written off in 1994 and 1993. Coverages in 1995 exclude the economic effect of the 1995 Gas Settlement ($44.2 million, pretax).

Electric Department Statistics

Year Ended December 31	1995	1994	1993	1992	1991	1990
Electric Revenue **(000's)**						
Residential	$254,292	$243,593	$235,286	$220,866	$212,327	$197,61[illegible]
Commercial	214,491	206,910	196,456	184,815	181,561	165,445
Industrial	157,496	150,690	147,396	142,392	141,001	130,012
Other (includes unbilled revenue)	70,302	56,955	59,817	60,194	54,041	58,861
Electric revenue from our customers	696,581	658,148	638,955	608,267	588,930	551,930
Other electric utilities	25,884	16,605	16,361	25,541	28,612	42,465
Total electric revenue	722,465	674,753	655,316	633,808	617,542	594,395
Electric Expense **(000's)**						
Fuel used in electric generation	44,190	44,961	45,871	48,376	65,105	76,420
Purchased electricity	54,167	37,002	31,563	29,706	27,683	34,264
Other operation	195,181	187,594	188,684	183,118	168,610	155,289
Maintenance	44,032	47,295	52,464	53,714	57,032	53,880
Depreciation and amortization	78,812	75,211	72,326	73,213	72,746	67,302
Taxes—local, state and other	102,380	97,919	96,043	94,841	86,925	77,323
Total electric expense	518,762	489,982	486,951	482,968	478,101	464,478
Operating Income before Federal Income Tax	203,703	184,771	168,365	150,840	139,441	129,917
Federal income tax	59,500	52,842	43,845	38,046	31,390	30,670
Operating Income from Electric Operations **(000's)**	$144,203	$131,929	$124,520	$112,794	$108,051	$ 99,247
Electric Operating Ratio %	46.7	47.0	48.6	49.7	51.6	53.8
Electric Sales—KWH **(000's)**						
Residential	2,144,718	2,117,168	2,123,277	2,084,705	2,087,910	2,066,859
Commercial	2,064,813	2,028,611	1,986,100	1,938,173	1,931,024	1,890,029
Industrial	1,964,975	1,860,833	1,892,700	1,929,720	1,920,075	1,923,935
Other	531,311	513,675	504,987	503,388	508,368	488,121
Total customer sales	6,705,817	6,520,287	6,507,064	6,455,986	6,447,377	6,368,944
Other electric utilities	1,484,196	1,021,733	743,588	1,062,738	1,034,370	1,316,37[illegible]
Total electric sales	8,190,013	7,542,020	7,250,652	7,518,724	7,481,747	7,685,323
Electric Customers at December 31						
Residential	306,601	304,494	302,219	300,344	298,440	296,110
Commercial	30,426	29,984	29,635	29,339	28,856	28,804
Industrial	1,347	1,361	1,382	1,386	1,388	1,428
Other	2,711	2,670	2,638	2,605	2,558	2,553
Total electric customers	341,085	338,509	335,874	333,674	331,242	328,895
Electricity Generated and Purchased—KWH **(000's)**						
Fossil	1,631,933	1,478,120	1,520,936	2,197,757	2,146,664	2,505,110
Nuclear	4,645,646	4,527,178	4,495,457	4,191,035	4,391,480	4,016,721
Hydro	171,886	218,129	199,239	278,318	174,239	244,539
Pumped storage	237,904	247,550	233,477	226,391	240,206	269,966
Less energy for pumping	(361,144)	(371,383)	(355,725)	(344,245)	(364,520)	(405,966)
Other	1,565	1,245	2,559	811	1,269	20,408
Total generated—net	6,327,790	6,100,839	6,095,943	6,550,067	6,589,338	6,650,778
Purchased	2,343,484	1,998,882	1,646,244	1,389,875	1,451,208	1,498,089
Total electric energy	8,671,274	8,099,721	7,742,187	7,939,942	8,040,546	8,148,867
System Net Capability—KW at December 31						
Fossil	529,000	532,000	541,000	541,000	541,000	541,000
Nuclear	640,000	617,000	620,000	617,000	622,000	621,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	28,000	29,000	29,000	29,000	29,000	29,000
Purchased	375,000	375,000	347,000	348,000	354,000	356,000
Total system net capability	1,619,000	1,600,000	1,584,000	1,582,000	1,593,000	1,594,000
Net Peak Load—KW	1,425,000	1,374,000	1,333,000	1,252,000	1,297,000	1,208,000
Annual Load Factor—Net %	57.6	58.8	59.1	62.5	61.7	64.[illegible]

Gas Department Statistics

Year Ended December 31	1995	1994	1993	1992	1991	1990
Gas Revenue (000's)						
Residential	$ 4,081	$ 5,935	$ 5,526	$ 6,456	$ 6,354	$ 6,508
Residential spaceheating	226,946	221,927	196,411	183,405	157,458	159,501
Commercial	48,938	50,318	45,620	44,274	40,196	43,534
Industrial	6,293	7,254	6,346	6,418	6,761	9,674
Municipal and other (includes unbilled revenue)	7,605	40,627	39,805	21,171	24,959	17,279
Total gas revenue	293,863	326,061	293,708	261,724	235,728	236,496
Gas Expense (000's)						
Gas purchased for resale	167,762	194,390	166,884	141,291	129,779	132,512
Other operation	58,727	48,302	46,697	43,506	39,830	39,307
Maintenance	5,194	7,774	9,229	9,006	8,383	8,510
Depreciation	12,781	12,250	11,851	11,815	11,435	10,465
Taxes—local, state and other	31,514	31,859	30,849	29,411	26,724	23,711
Total gas expense	275,978	294,575	265,510	235,029	216,151	214,505
Operating Income before Federal Income Tax	17,885	31,486	28,198	26,695	19,577	21,991
Federal income tax	6,715	8,403	5,485	5,545	2,869	3,820
Operating Income from Gas Operations (000's)	$ 11,170	$ 23,083	$ 22,713	$ 21,150	$ 16,708	$ 18,171
Gas Operating Ratio %	79.7	76.8	75.9	74.1	75.5	76.3
Gas Sales—Therms (000's)						
Residential	7,167	6,535	6,871	8,780	9,151	9,067
Residential spaceheating	280,763	283,039	295,093	287,623	255,988	246,749
Commercial	68,380	72,410	78,887	78,996	72,167	72,971
Industrial	9,560	11,420	12,030	12,438	13,120	17,427
Municipal	8,219	10,230	12,188	11,410	10,677	12,551
Total gas sales	374,089	383,634	405,069	399,247	361,103	358,765
Transportation of customer-owned gas	146,149	136,372	124,436	126,140	109,835	101,985
Total gas sold and transported	520,238	520,006	529,505	525,387	470,938	460,750
Gas Customers at December 31						
Residential	17,443	17,836	18,389	19,114	21,448	22,410
Residential spaceheating	238,267	235,313	231,937	228,096	222,918	219,242
Commercial	18,978	18,742	18,636	18,378	18,151	17,920
Industrial	879	905	924	932	921	960
Municipal	981	988	1,001	1,010	983	984
Transportation	655	558	466	424	423	401
Total gas customers	277,203	274,342	271,353	267,954	264,844	261,917
Gas—Therms (000's)						
Purchased for resale	237,728	262,267	347,778	360,493	384,643	366,684
Gas from storage	152,852	134,802	76,378	53,757	16,755	—
Other	1;800	2,959	1,039	1,061	1,617	2,525
Total gas available	392,380	400,028	425,195	415,311	403,015	369,209
Cost of gas per therm (cents)	45.80¢	50.00¢	36.79¢	35.35¢	32.96¢	36.03¢
*Total Daily Capacity—Therms at December 31**	5,230,000	5,625,000	5,625,000	4,485,000	4,485,000	4,485,000
Maximum daily throughput—Therms	3,980,000	4,735,690	3,864,850	3,768,470	3,539,260	3,539,820
Degree Days (Calendar Month)						
For the period	6,535	6,699	7,044	6,981	6;146	5,924
Percent colder (warmer) than normal	(3.0)	(0.6)	4.4	3.4	(8.4)	(11.8)

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

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ation

Investor Information

Corporate Address
Rochester Gas and
Electric Corporation
89 East Avenue
Rochester, NY 14649-0001
(716) 546-2700

Financial Information
Shareholders can access RG&E financial information as soon as it is released by calling our automated investor communications system at (800) 724-8833. Local shareholders can reach the system by calling 724-8833. Designed for use on a touch tone phone, the system is available to shareholders 24 hours a day. The primary options are as follows:

- Access shareholder services
- Access bondholder services
- Hear the latest dividend and earnings releases
- Order Company financial reports

Quarterly financial results will typically be released in conjunction with the dividend payment dates.

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

Stock Transfer Agent
The First National Bank of Boston
c/o Boston EquiServe
Mail Stop: 45-02-64
P.O. Box 644
Boston, MA 02102-0644
(800) 736-3001

Telecommunication Device for the Deaf
(800) 952-9245

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

Dividends

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 stock transfer agent.

Dividend Reinvestment
RG&E offers a dividend reinvestment plan as a service to Common Stock shareholders who wish to purchase additional shares. In addition to full or partial reinvestment of dividends, the plan gives shareholders the opportunity to make direct cash investments ranging from $50 to $5,000 as often as once a month. For further information, contact our stock transfer agent.

Annual Meeting
RG&E's 1996 annual meeting of shareholders will be held at the Rochester Riverside Convention Center on Wednesday, April 24, 1996 at 11 am.

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.

Form 10-K Annual Report
Shareholders may obtain a copy of the Company's 1995 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by calling (800) 724-8833 or writing to the Corporate Secretary.

Rochester
Gas and Electric
Corporation

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Board of Directors and Officers

Board of Directors
(as of January 1, 1996)

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
(Deceased February 1, 1996)

Jay T. Holmes √
Executive Vice President and
Chief Administrative Officer,
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

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

Officers
(as of January 1, 1996)

Roger W. Kober
Chairman of the Board, President
and Chief Executive Officer
Age 62, Years of Service, 30

Thomas S. Richards
Senior Vice President,
Energy Services
Age 52, Years of Service, 4

Robert E. Smith
Senior Vice President,
Energy Operations
Age 58, Years of Service, 36

J. Burt Stokes
Senior Vice President, Corporate
Services and Chief Financial Officer
Age 53, Years of Service, 0*

David C. Heiligman
Vice President, Finance and
Corporate Secretary
Age 55, Years of Service, 32

Robert C. Mecredy
Vice President,
Nuclear Operations
Age 50, Years of Service, 24

Wilfred J. Schrouder, Jr.
Vice President,
Customer Development
Age 54, Years of Service, 33

Daniel J. Baier
Controller
Age 49, Years of Service, 12

Mark Keogh
Treasurer
Age 50, Years of Service, 24

Jessica S. Raines
Auditor
Age 38, Years of Service, 0**

* Elected Senior Vice President, Corporate Services and Chief Financial Officer, effective January 1,1996

** Elected Auditor of the Company, effective September 11,1995

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