CATEGORY 1

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9903160358 DOC.DATE: 98/12/31 NOTARIZED: NO DOCKET #
FACIL:50-244 Robert Emmet Ginna Nuclear Plant, Unit 1, Rochester G 05000244
AUTH.NAME AUTHOR AFFILIATION
* Rochester Gas & Electric Corp.
RECIP.NAME RECIPIENT AFFILIATION

SUBJECT: "RG&E 1998 Annual Rept."

DISTRIBUTION CODE: IE47D COPIES RECEIVED:LTR 0 ENCL 1 SIZE: 60
TITLE: 50.59 Annual Report of Changes,Tests or Experiments Made W/out Approv

NOTES:License Exp date in accordance with 10CFR2,2.109(9/19/72). 05000244

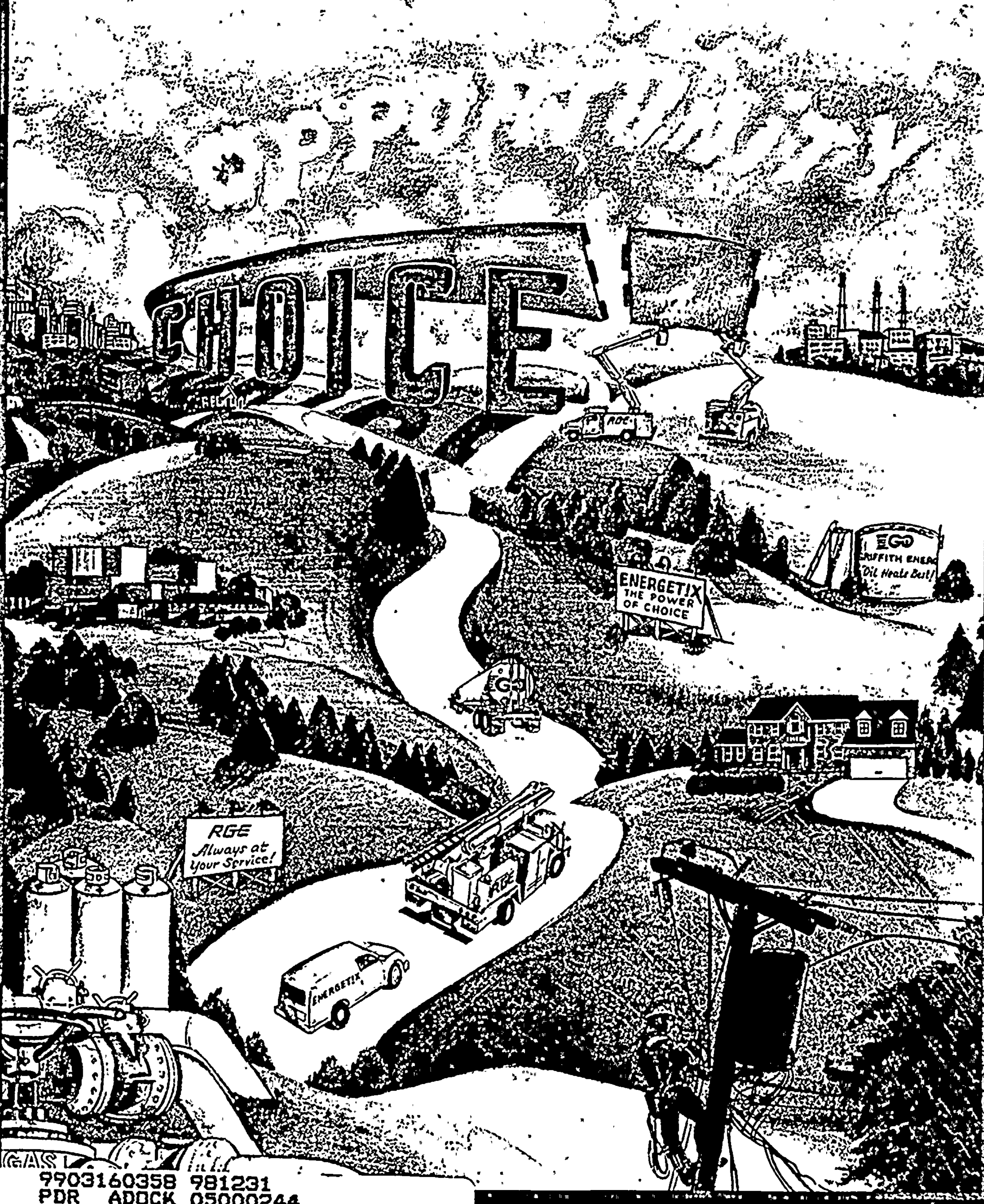
	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL
	PD1-1 PD	1	0	VISSING,G.	1	1
INTERNAL:	FILE CENTER	1	1	RGN1 FILE 01	1	1
EXTERNAL:	NOAC	1	1	NRC PDR	1	1

C A T E G O R Y 1 D O C U M E N T

NOTE TO ALL "RIDS" RECIPIENTS:
PLEASE HELP US TO REDUCE WASTE. TO HAVE YOUR NAME OR ORGANIZATION REMOVED FROM DISTRIBUTION LISTS OR REDUCE THE NUMBER OF COPIES RECEIVED BY YOU OR YOUR ORGANIZATION, CONTACT THE DOCUMENT CONTROL DESK (DCD) ON EXTENSION 415-2083

TOTAL NUMBER OF COPIES REQUIRED: LTTR 0 ENCL 5

Rochester Gas and Electric Corporation
1998 Annual Report

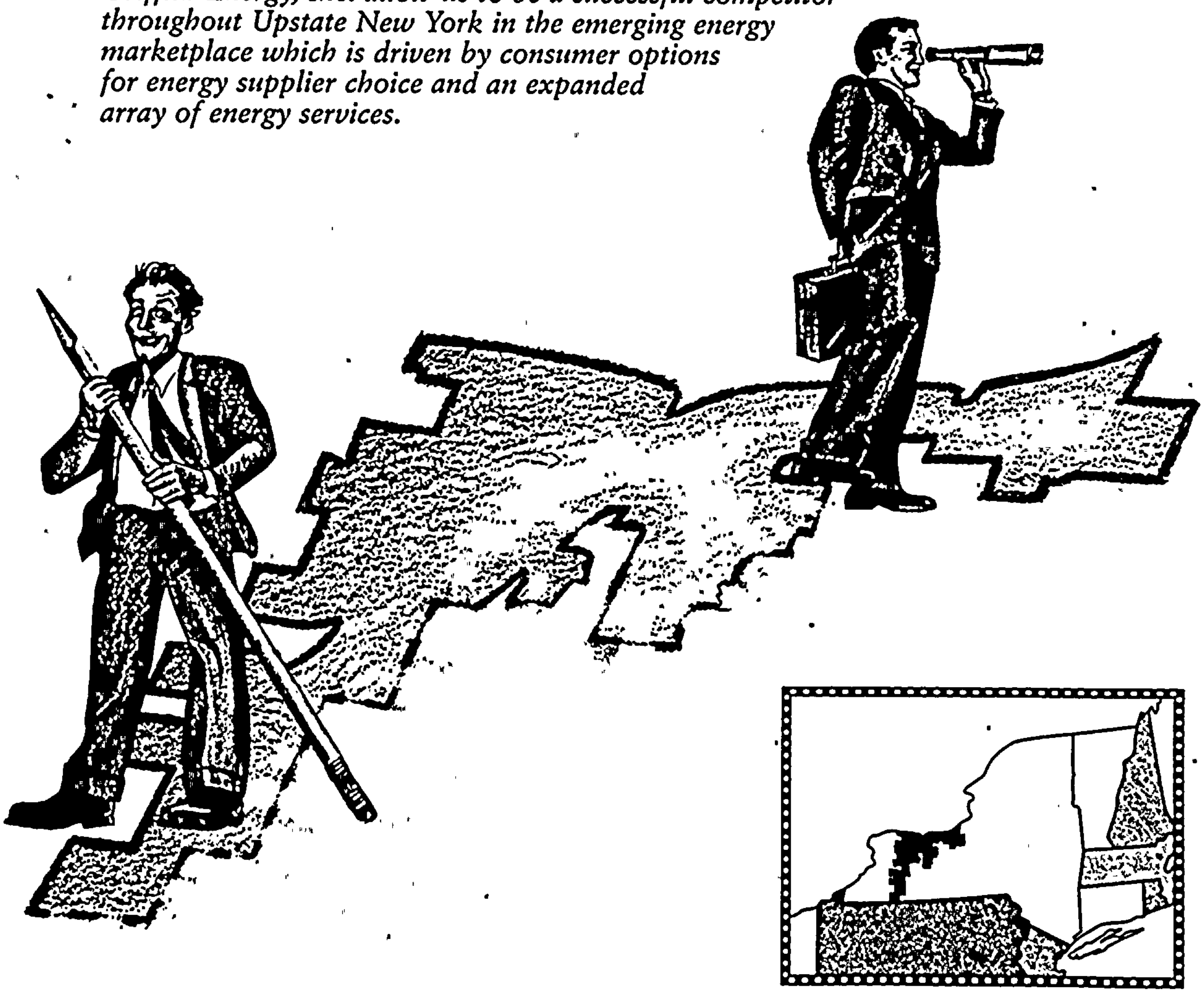


RG&E Erasing the Boundaries

Currently RG&E supplies electric and gas service wholly within upstate New York in a nine-county area centering about the City of Rochester. The journey to energy choice for consumers opens up new opportunities. We're no longer bounded by the borders of our traditional service franchise territory.

Our traditional services include the production, transmission, distribution and sales of energy in a service territory of about one million people. The service territory is well diversified among residential, commercial and industrial customers. The City of Rochester is the fourth largest in New York State and a major industrial center. Multi-national commerce in the Greater Rochester Region accounts for 40 percent of all exports from New York State and makes our area the number one per-capita exporting community in the nation. Our territory also has a substantial suburban area with commercial growth and large, prosperous farming regions.

RG&E's unregulated subsidiaries, Energetix, Inc. and Griffith Energy, Inc. allow us to be a successful competitor throughout Upstate New York in the emerging energy marketplace which is driven by consumer options for energy supplier choice and an expanded array of energy services.



Financial Highlights

	1998	1997	% Change
Financial Data (Dollars in Thousands)			
Operating revenues: Electric	$687,970	$700,329	(2)
Gas	$275,177	$336,309	(18)
Other*	$ 71,215	—	—
Operating expenses	$907,202	$891,297	2
Operating income	$127,160	$145,341	(13)
Net income	$ 94,138	$ 95,360	(1)
Earnings applicable to common stock	$ 89,296	$ 89,555	—
Rate of return on average common equity	11.22%	11.00%	2
Common Stock Data			
Weighted average number of shares outstanding (thousands)			
—Basic	38,462	38,853	(1)
—Diluted	38,600	38,909	(1)
Per common share:			
Earnings—Basic	$2.32	$2.30	1
Earnings—Diluted	$2.31	$2.30	—
Dividends Paid	$1.80	$1.80	—
Book Value (year end)	$20.94	$20.80	1
Year-end market price	$31.25	$34.00	(8)
Number of Common Stock Shareholders at December 31	28,995	31,337	(7)
Operating Data			
Sales (thousands)			
Kilowatt-hours to retail customers	6,562,532	6,805,719	(4)
Kilowatt-hours to wholesale customers	1,671,959	1,218,794	37
Therms of gas sold and transported	472,933	538,062	(12)
Net additions to utility plant, less allowance for funds used during construction (thousands)	$129,286	$84,068	54
Employees (year end)	2,333	1,958	19

*Unregulated business revenues

SHAREHOLDER'S LETTER

It was just a few minutes past Midnight on September 7 – dark but calm. The clock placed Rochester in the early morning hours of Labor Day 1998. Moments later and without warning, the calm was torn apart by an eight-mile-wide channel of 80-mile-per-hour winds that bent torrential rains horizontally and forged a path of destruction down a 100-mile corridor in upstate New York. It spent itself in just 45 minutes but left behind an alley of devastation strewn with uprooted trees, smashed homes, broken power poles, and tangled and severed power lines. More than 100,000 RG&E electric customers were without power.

It was nothing new for us in 1998. It turned out to be a record-breaking year for declared electric storm emergencies - nearly a dozen and more than twice the yearly average. But, using every resource available in following our well-rehearsed electric emergency response plan in the Labor Day storm, we were able to restore power to half of our affected customers within 24 hours and to all the rest within a week.

Besides testing our planning and resources, the Labor Day storm served as a reminder of what is important to our customers. While they welcome the significant changes in our business that are bringing them a choice of energy services suppliers, they do not expect to be put at risk during the transition. Unlike the deregulation of many other industries, the transition of this industry cannot leave any customers behind. Whether or not aided by competitive choice, we are expected to bring lower rates, high reliability and access to everyone, while continuing low-income, environmental and other social programs. This balancing act requires that our company continually recognize and respond to all of these challenges. We welcome this challenge and appreciate the customers who have given us the opportunity to serve them for many years. In this letter I will share with you some of the progress we made during the 150th year of our history in meeting our challenges.

Whatever else we do, we need to keep the lights on and the gas flowing to our customers. We did it well in 1998, as our predecessors had done before us. Adding to excellent storm response, our power plant performance was also strong, topped by a record year for our Ginna Nuclear Power Plant. The Ginna plant operated without shutdowns in 1998, lowering our cost of production and providing a reliable source of power for our customers.

However, doing well with what we have is not enough. We continued to invest in our distribution system to improve its performance and make the changes necessary to give customers a choice of suppliers. A new more flexible customer information system was also installed, along with new networked personal and enterprise computing systems.

Not all the challenges originated from within our industry. For example, our response to the much publicized Y2K problem was in full swing during 1998. You have probably learned that the problem stems from computer systems that recognize only the last two digits of a year. They therefore cannot distinguish the coming year 2000 from the year 1900. At RG&E we've been working on this issue since 1996. And while there is a certain amount of exaggeration surrounding the description of this problem, we are taking it very seriously and, as is described in the Management Discussion and Analysis section of this annual report, we will be ready to provide reliable energy in the next century.

All this takes place as we continue to reduce electric costs for the customers served under our regulated rates. Residential customers will see an average reduction of ten percent by 2001, and commercial and industrial customers will realize savings of 15 percent or more. Our gas distribution rates have not increased since 1994, and there will be no increase for at least another heating season as we work with the Public Service Commission to bring increased customer choice to the gas business.

I have been talking about the journey to energy choice for several years now in this letter and at our annual meetings. With the arrival of electric energy provider choice for our customers, we have moved beyond anticipation to implementation.The first phase of customer choice in electric supply started in the summer of 1998 and by the end of January this year all ten percent of our electric load that was eligible was being served by eight competing, unregulated energy service companies, including our own subsidiary, **ENERGETIX**℠. This was being done under our "single retailer" model, unique to RG&E in New York State. Under this model, the new competitive energy services company becomes the single supplier of electric service to the end-use customer. The energy services company bills the customer. RG&E, in turn, bills the new energy company for the service of moving power through our system. The new companies become our customers, and we are committed to developing mutually beneficial business relationships with them. There is a tremendous amount of change and work behind this shift and it has been accomplished in record time when compared to similar shifts in other, often less essential, industries.

To this point I have been talking about maintaining operational excellence in our traditional regulated utility business and preparing that business and its systems for the introduction of competitive choice. These components of our business are each important in their own right. The challenge, however, is to balance them by developing new sources of revenue and earnings. Our response to this challenge prompted the most exciting change for us last year.

In 1998 we began to operate **ENERGETIX**℠, an unregulated subsidiary that delivers energy products and services to customers throughout upstate New York. A great deal of time and effort was directed at the development of a viable and diversified **ENERGETIX**℠ business plan. It is a plan that is flexible to the evolving competitiveness of the retail electric and natural gas markets over time and will meet our goal of becoming the premier energy service company in upstate New York. Since its inception, **ENERGETIX**℠ has put the plan into action and succeeded in attracting thousands of commercial and residential gas and electric customers, as well as customers for its ServiceCare℠ Appliance Warranty product line. Operating from separate headquarters in Rochester since June, 1998, **ENERGETIX**℠ has grown to 26 employees.

In August 1998, **ENERGETIX**℠ acquired Griffith Oil, Inc., the second largest oil and propane distribution company in New York State, with 65,000 retail customers, 60,000 of whom reside outside RG&E's service territory. Griffith operates throughout upstate New York from 16 offices and distribution centers with 338 employees. It provides a diversification of

the **ENERGETIX**℠ product line to include liquid fuels and a base from which to expand the **ENERGETIX**℠ electric and natural gas business. This diversification of products and the established presence of Griffith Oil will allow us to capitalize economically on the emerging opportunities in upstate New York, outside of our service territory, where competitive choice has just begun. We're off to a fine start. From virtually nothing in 1997, we finished 1998 in the unregulated energy business with thousands of customers all over upstate New York, 364 employees and $81.8 million in revenue.

Our strategic focus on upstate New York is designed to have **ENERGETIX**℠ build upon our existing strengths. Griffith is well established throughout the region and we understand how to do business here. Having continually produced high levels of reliability and customer satisfaction with the lowest rates in the region, RG&E enjoys a fine reputation. While our regulated service territory has about 344,000 electric customers, our core market contains more than two million additional customers. The opportunities are great.

Looking back on 1998, I believe we can fairly conclude that we excelled at operating our business and adapting to competitive choice while experiencing dramatic changes in the nature of our industry. We managed the impact of a very warm heating season, lower rates, the cost of adapting the system to competitive choice and investments in growing the unregulated business, yet still managed to increase per-share earnings modestly. However, after a terrific performance in 1997, the performance of our stock in 1998 was disappointing.

Investors and analysts are trying to understand the changes and evaluate their impact on energy utility stocks. This is a time of change and uncertainty in our industry and it's reflected in the pricing of utility stocks today. Although our three-year return compares very favorably with the other companies in the Edison Electric Institute Index, our stock performance in 1998 was disappointing. In 1998 utility stock prices were influenced by large company growth strategies that included global merger and acquisition activity along with power plant sales by companies wanting to get out of the generating business. In view of our significant commitment to nuclear generation, sales of these assets at today's prices are not in the best interest of our shareholders.

There'll be a number of factors, some real, some imagined, that will affect the value of our stock both positively and negatively over time. We cannot influence all of the factors. We can, though, run the business well, adopt a solid and flexible plan for growth and execute it. That is what we are doing and I believe this is what will continue to make RG&E a solid investment. We very much appreciate the support of our shareholders as we move forward with the plan on this journey.

In 1999 the journey to competitive choice will continue. An additional ten percent of our electric load will become eligible to be served by competitive suppliers this summer. The electric transmission system in New York, including RG&E's transmission lines, is scheduled later this year to come under the day-to-day control of an Independent System Operatc (ISO) regulated by the Federal Energy Regulatory Commission. The ISO's job is to ensure fair transmission access and reliable operation as electric energy competitors move power throughout the state. The regulatory process of creating the ISO is not complete and the market for capacity and energy will not fully develop until this essential system goes into operation

While RG&E was not required to do so, many other electric energy utilities in New York State agree as part of their settlements with the PSC, to sell their fossil-fueled and hydro electric power plants. Auctio were conducted in 1998 and the sales are expected tc be concluded in 1999, opening the wholesale electric market to competitive forces never before seen here.

Our generating business will also change in 19ʕ We will close our coal-fired Beebee Station and activate the Allegany gas-fired plant we acquired recentl as part of the settlement of our long standing disputc with an independent power producer. Of significant importance to RG&E, given our relatively heavy

reliance on nuclear generation, is the Public Service Commission's new generic proceeding to investigate the future of nuclear power in New York State. This proceeding, which will consider both changes in the ratemaking treatment of the plants as well as possible divestiture, is expected to be concluded later this year.

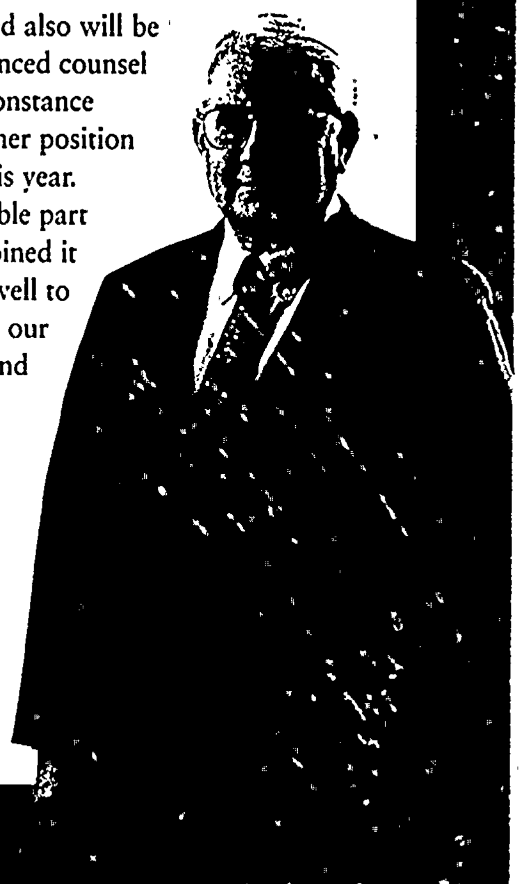
We do not believe that the possible sale of any nuclear plant should be considered apart from the total impact on customers who, under any proposal, will be expected to continue to pay much of the unrecovered cost of these plants while being exposed to an immature and potentially volatile unregulated energy market. We need to be sure that we can deliver on the promise to customers that they will have available, if they choose, declining fixed regulated rates, before we lose control of the energy cost. The size of our investment in nuclear power makes this a very important issue for us, but it is equally important to our customers and the supply of energy in New York State, which is 20 percent nuclear. This is not something that can be subjected to experimentation or rushed to a conclusion.

This is also the year in which we are scheduled to address bringing competitive choice to the retail natural gas market. While the ability to choose another gas commodity supplier has been available to all customers since 1996, in practice it has been mostly confined to the largest customers. The Public Service Commission is now considering the issues that are involved in making supplier choice available to all customers. This raises many of the issues already involved in the on-going changes in electric supply. In particular, what role the regulated distribution companies will continue to play in supplying the gas commodity is under discussion. We will be actively involved in this process this year and expect to begin to implement changes in the fall.

As contemplated by the regulatory changes that began last year, we are proposing to form a holding company this year to be called RGS Energy Group, Inc. Shareholder approval for this proposal will be the focus of our upcoming annual meeting. A rather lengthy, but necessary and complete, description of the information has been mailed to shareholders along with this annual report. I urge you to review the contents of that document so that you may better understand this important milestone in our history.

I began this letter by mentioning the devastating Labor Day Storm that affected a third of our electric customers. I can't say enough about our RG&E people for their outstanding performance, particularly the remarkable restoration of power in the wake of that storm on Labor Day. Moreover I want to express my sincere appreciation for the effort of all RG&E people in the day-to-day work of making your company a reliable, safe and customer friendly energy provider. Their performance reflects the new RG&E that is being shaped and managed to do more through efficiency, process planning and innovation. This commitment to deal positively with change was confirmed by a five-to-one margin vote by our distribution employees to reject an attempt to bring a union to the company.

Finally I want to extend our thanks to Robert E. Smith who retired last year after 39 years of dedicated service to RG&E. His engineering expertise and fine management style led our electric generating operations to their high standards of excellent and performance. Missed also will be the wise advice and balanced counsel of our board member Constance Mitchell who will leave her position at the annual meeting this year. Connie has been a valuable part of our Board since she joined it in 1981. We would do well to find such people to serve our Company in the future and I wish them both well.



Thomas S. Richards
February 1, 1999
Chairman of the Board,
President and Chief
Executive Officer

Management's Discussion and Analysis

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following is Management's assessment of certain significant factors affecting the financial condition and operating results of Rochester Gas and Electric Corporation ("RG&E") and its subsidiaries (RG&E, together with its subsidiaries, is referred to as "the Company") over the past three years. The Consolidated Financial Statements and the Notes thereto contain additional data. For the twelve months ended December 31, 1998, 66 percent of the Company's operating revenues were derived from electric service, 27 percent from natural gas service, and 7 percent from unregulated businesses.

The discussion presented below contains statements which are not historic fact and which can be classified as forward looking. These statements can be identified by the use of certain words which suggest forward looking information, such as "believes," "will," "expects," "projects," "estimates" and "anticipates". They can also be identified by the use of words which relate to future goals or strategies. In addition to the assumptions and other factors referred to specifically in connection with the forward looking statements, some of the factors that could have a significant difference in whether the forward looking statements ultimately prove to be accurate include:

1. any state or federal legislative or regulatory initiatives that affect the cost or recovery of investments necessary to provide utility service in the electric and natural gas industries. Such initiatives could include, for example, changes in the regulation of rate structures or changes in the speed or degree to which competition occurs in the electric and natural gas industries;
2. any changes in the ability of the Company to recover environmental compliance costs through increased rates;
3. any changes in the regulatory status of nuclear generating facilities and their related costs, including recovery of costs related to spent fuel and decommissioning;
4. any changes in the rate of industrial, commercial and residential growth in the Company's service territories;
5. the development of any new technologies which allow customers to generate their own energy or produce lower cost energy;
6. any unusual or extreme weather or other natural phenomena;
7. the ability of the Company to manage profitably its new unregulated operations;
8. certain unknowable risks involved in operating unregulated businesses in new territories and new industries;
9. the timing and extent of changes in commodity prices and interest rates;
10. any unanticipated developments associated with identifying, assessing, fixing and testing the modifications necessary to mitigate Year 2000 compliance problems, including the possible indirect impact of customers, suppliers and other business partners who do not sufficiently mitigate their Year 2000 compliance problems; and
11. any other considerations that may be disclosed from time to time in the Company's publicly disseminated documents and filings.

Shown below is a listing of the principal items discussed.

Earnings Summary

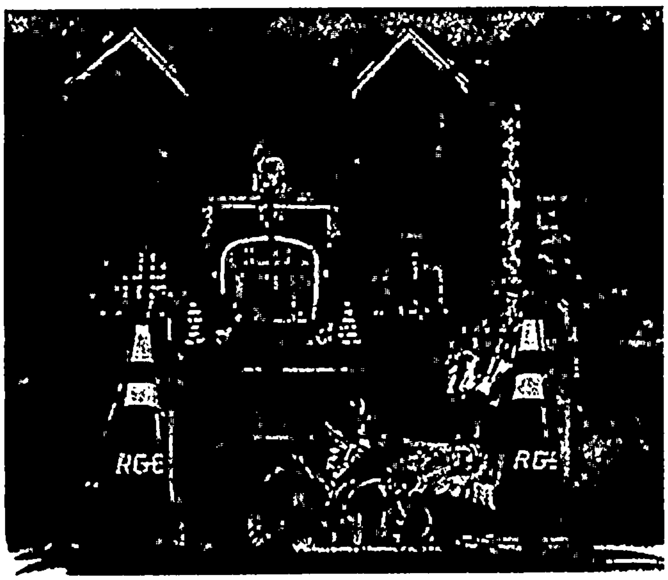
Operating performance of the Company's generating plants, expense control, the sale of electric energy to wholesale customers, and the recognition of $17.4 million of non-recurring income during the year (see Other Statement of Income Items) allowed the Company to keep 1998 earnings applicable to Common Stock at about the same level as 1997, despite rate decreases and warmer temperatures during the 1998 heating seasons.

Basic earnings per share were $2.32 in 1998, compared with $2.30 in 1997, and $2.32 a year earlier. Earnings per Common Share - Diluted were $2.31 in 1998, $2.30 in 1997, and $2.32 in 1996. Earnings per share in 1998 were improved by approximately $.02 per share resulting from the buyback of Common Stock under the Company's Stock Repurchase Program.

For the twelve month period ending December 31, 1998, the Company's unregulated subsidiary, Energetix, Inc., had a pretax operating loss of $4.1 million, which reduced consolidated earnings by approximately $0.06 per basic share. This loss is primarily due to initial start-up and marketing costs. Moreover, while Energetix was formed January 1, 1998, the first revenues were not received until April of 1998. In addition, revenues from Griffith Oil Co., Inc., a company acquired by Energetix, only reflect sales since acquisition in August 1998. Energetix revenues for 1999 from electric and gas operations are expected to increase over 1998 levels as Energetix expands its customer base, although no assurance may be given that Energetix will achieve a net operating gain in 1999 or that new business opportunities will not impact its operating results.

The impact of developing competition in the energy marketplace may affect future earnings. The Competitive Opportunities Case Settlement (the "Settlement", see description below) allows for a phase-in to open electric markets while lowering customer prices and establishing an opportunity for competitive returns on shareholder investments. The nature and magnitude of the potential impact of the Settlement on the business of the Company will depend on several factors, including the availability of qualified energy suppliers in the Company's service territory, the degree of customer participation and ultimate selection of an alternative energy supplier, the Company's ability to be competitive by controlling its operating expenses, and the Company's ultimate success in the development of its unregulated business opportunities as permitted under the Settlement.

Although under the current regulatory environment the Company does not earn a return on the gas commodity it acquires for distribution, future earnings may also be affected, in part, by the ultimate outcome of a November 1998 New York State Public Service Commission ("PSC") gas restructuring policy statement. That policy statement concludes that the most effective way to establish a robust competitive market for gas supply in New York State is for local distribution businesses, such as the Company, to exit the merchant function of acquiring gas for distribution. In addition, local distribution companies must cease assigning capacity to customers migrating from sales to transportation service no later than April 1, 1999. The nature and magnitude of the potential impact of these policies will depend on individual negotiations the Company will undertake with PSC Staff and other interested parties on RG&E-specific restructuring, as well as a number of Statewide collaborative efforts that will deal with such issues as provider of last resort, reliability, recovery of stranded costs, and market power as the transition is made to a more competitive gas business.



Competition

PSC Competitive Opportunities Case Settlement.

During 1996 and 1997, RG&E, the staff of the PSC and several other parties negotiated an agreement which was approved by the PSC in November 1997 (the "Settlement"). The Settlement sets the framework for the introduction and development of open competition in the electric energy marketplace and lasts through June 30, 2002. Over this time, the way electricity is provided to customers will fundamentally change. In phases, RG&E will allow customers to purchase electricity, and later capacity commitments, from sources other than RG&E through its retail access program, Energy Choice. These energy service companies will compete to package and sell energy and related services to customers. The competing energy service companies will purchase distribution services from RG&E who will remain the sole provider of distribution services, and will be responsible for maintaining the distribution system and for responding to emergencies.

The Settlement sets RG&E's electric rates for each year during its five-year term. Over the five-year term of the Settlement, the cumulative rate reductions for the bundled service will be as follows: Rate Year 1 (July 1, 1997 to June 30, 1998) $3.5 million; Rate Year 2 $12.8 million; Rate Year 3 $27.6 million; Rate Year 4 $39.5 million; and Rate Year 5 $64.6 million.

The Settlement permits RG&E to fund its unregulated operations with up to $100 million.

In the event that RG&E earns a return on common equity in excess of an effective rate of 11.50 percent over the entire five-year term of the Settlement, 50 percent of such excess will be used to write down deferred costs accumulated during the term. The other 50 percent of the excess will be used to write down accumulated deferrals or investment in electric plant or Regulatory Assets (which are deferred costs whose classification as an asset on the balance sheet is permitted by SFAS-71, Accounting for the Effects of Certain Types of Regulation). If certain extraordinary events occur, including a rate of return on common equity below 8.5 percent or above 14.5 percent, or a pretax interest coverage below 2.5 times, then either the Company or any other party to the Settlement would have the right to petition the PSC for review of the Settlement and appropriate remedial action.

The Settlement requires RG&E to functionally separate its three regulated operations: distribution, generation and retailing. Additionally, unregulated energy retailing operations must be

structurally separate from the regulated utility functions. Although the Settlement provides incentives for the sale of generating assets, it does not require RG&E to divest generating or other assets or write-off stranded costs. Additionally, RG&E will be given a reasonable opportunity to recover substantially all of its prudently incurred costs, including those pertaining to generation and purchased power.

RG&E believes that the Settlement will not adversely affect its eligibility to continue to apply certain accounting rules applicable to regulated industries. In particular, RG&E believes it will continue to be eligible for the treatment provided by SFAS-71 which allows RG&E to include assets on its balance sheet based on its regulated ability to recoup the cost of those assets. However, this may not be the case with respect to certain operational costs associated with non-nuclear generation (see Note 10 of the Notes to Financial Statements under the heading Other Matters, EITF Issue 97-4, Deregulation of the Pricing of Electricity).

The Company's retail access program, Energy Choice, was approved by the PSC as part of the Settlement and went into effect on July 1, 1998. Details of the Energy Choice Program are discussed below.

One party to the Settlement negotiations has commenced an action for declaratory and injunctive relief as to certain provisions of the Settlement and the PSC's approval of it. The Company is unable, at this time, to predict the outcome of this action.

BUSINESS AND FINANCIAL STRATEGY.

Under the terms of the Settlement, the Company has functionally separated its generation, distribution, and regulated energy services businesses. Consistent with the Settlement, the Company has begun to implement a business and financial strategy which consists of the following: (1) the reorganization of its corporate structure into a holding company in order to more fully implement the separation of its regulated and unregulated businesses, (2) the establishment of a separate unregulated subsidiary, Energetix, Inc. ("Energetix"), which will be able to compete for energy, energy services and products both in and outside the Company's existing franchise service territory, and (3) the development of an integrated financial strategy that includes new business initiatives and a Common Stock share repurchase program of $145 million.

Energy Choice. On July 1, 1998, the Company launched its full-scale retail Energy Choice Program. There are three basic components of the sale of energy: the sale of electricity which is the amount of energy actually used by the consumer, the sale of capacity which is the ability through generating facilities or otherwise, to provide electricity when it is needed, and the sale of distribution, which is the physical delivery of electricity to the consumer. Historically, the Company has sold all three components bundled together for a fixed rate approved by the PSC. Up to ten percent of RG&E's retail electric customers can now seek out or be approached by alternative energy service companies for electricity to be delivered over RG&E's distribution system. Participation in Energy Choice is limited to no more than 10 percent of RG&E's total annual retail electric kilowatt-hour sales during the first year of the program. This limit increases to 20 percent the second year and 30 percent in the third year. In July, 2001, all retail customers will be eligible to purchase energy from alternative energy service companies.

The phase-in of the Energy Choice Program over the next few years eventually will give retail electric customers the opportunity to purchase energy, capacity and retailing services from competitive energy service companies. They may also continue to purchase fully bundled electric service from RG&E under existing retail tariffs.

Energy Choice adopts the single-retailer model for the relationship between the Company as the distribution provider, qualified energy service companies, and retail (end-use) customers. In this model, retail customers have the opportunity for choice in their energy service company and receive only one electric bill from the company that serves them. With the exception of emergency services, which

remain the Company's responsibility, the retail customers' primary point of contact is with their chosen energy service company.

Under the single-retailer model, energy service companies are responsible for buying or otherwise providing the electricity their retail customers will use, paying regulated rates for transmission and distribution, and selling electricity to their retail customers (the price of which would include the cost of the electricity itself and the cost to transport electricity through RG&E's distribution system).

Throughout the term of the Settlement, RG&E will continue to provide regulated and fully bundled electric service under its retail service tariff to customers who choose to continue with or return to such service, and to customers to whom no competitive alternative is offered.

Until the development of a wholesale market for generating capacity, there will be no suitable mechanism for the reallocation, from the regulated utility to the energy service company, of responsibility for ensuring adequate installed reserve capacity. Accordingly, during the initial "Energy Only" stage of the Energy Choice Program (July 1, 1998 to July 1, 1999), energy service companies will be able to choose their own sources of energy supply, while RG&E will continue to provide to them, through its bundled distribution rates, the generating capacity (installed reserve) needed to serve their retail customers reliably.

During the "Energy Only" stage, energy service companies have the option of purchasing "full-requirements" (i.e. delivery services and energy) from RG&E.

During the "Energy and Capacity" stage, scheduled to commence July 1, 1999, energy service companies will no longer have the option of purchasing "full-requirements" from RG&E and will be responsible for procuring generating capacity, as well as energy, to serve the loads of their retail customers. Distribution charges will be accordingly reduced as described below.

According to the terms of the Settlement, if a Statewide energy and capacity market is not implemented by July 1, 1999, RG&E may petition the PSC for a delay in the implementation of the "Energy and Capacity" stage of RG&E's retail access program. At this time, a functioning Statewide energy and capacity market does not exist (see discussion under FERC Open Access Transmission Orders and Company Filings). If a functioning Statewide energy and capacity market is not functioning in the near future, the Company will need to seek a delay of the scheduled commencement of the "Energy and Capacity" stage.

During the initial "Energy Only" stage of the Retail Access Program, RG&E's distribution rate will be set by deducting 2.3 cents per kilowatt-hour from its full service ("bundled") rates. The 2.3 cents per kilowatt-hour is comprised of 1.9 cents per kilowatt-hour (an estimate of the wholesale market price of electricity) plus 0.4 cents per kilowatt-hour for its avoided cost of retailing services. During the "Energy and Capacity" stage, RG&E's distribution rates will equal the bundled rate less RG&E's cost of the electric commodity and RG&E's non-nuclear generating capacity. During this stage of the program, RG&E's distribution rates will be set by deducting 3.2 cents per kilowatt-hour, inclusive of applicable gross receipts taxes, from its full service ("bundled") rates. The 3.2 cents per kilowatt-hour is comprised of 2.8 cents per kilowatt-hour (an estimate of the wholesale market price of electric energy and capacity, inclusive of gross receipts taxes) plus 0.4 cents per kilowatt-hour for its avoided cost of retailing services.

Through January 31, 1999, eight energy service companies, including Energetix, the Company's unregulated subsidiary, have been qualified by RG&E to serve retail customers under the Energy Choice Program. In addition to Energetix, these companies are Columbia Energy Power Marketing Corporation, Enserch Energy Services (New York), Inc., Florida Power & Light (FPL Energy Services), Inc., NEV East, L.L.C. (New Energy Ventures), Northeast Energy Services, Inc. (NORESCO), North American Energy, and Select Energy Inc. (Northeast Utilities Wholesale Power). As of January 31, 1999, all energy service companies have opted to purchase "full-requirements" from RG&E to serve their retail customers. As "full-requirements" customers, energy service companies are able to purchase electricity from RG&E at 1.9 cents per kilowatt-hour. RG&E has distributed approximately 670,000 (annualized) megawatt-hours to retail customers of energy service companies,

thereby reaching 100 percent of the first-year cap of 10% for the full-scale program. This impact was not significant because the loss of RG&E retail sales is roughly offset by the sale of distribution service and electricity to energy service companies. Although it is too early to quantify at this time, a substantial part of this revenue loss is expected to be offset by cost reductions resulting from the shift in retailing responsibilities from RG&E to energy service companies.

Looking ahead to the latter part of 1999, up to 20% of the total annual electric sales will be eligible for retail access. With implementation of the Energy and Capacity phase of the full-scale program, the Company will also be shifting the responsibility for purchasing not only electricity, but also capacity to these energy service companies. Similarly, there will be a slight revenue loss as a result of the increased back-out rate. However, the Company expects to manage this revenue impact with offsetting savings in costs no longer incurred for the acquisition and maintenance of capacity and increasing wholesale revenues through the sale of available capacity.

The PSC initiated a Statewide proceeding to recommend "uniform business rules" dealing with electric retail access programs for each of the utilities it regulates. In addition to this proceeding, there are three other proceedings underway: Electronic Data Interchange, Competitive Metering, and the Single Billing Option. These proceedings are intended to bring more consistency among New York State utilities and potentially offer additional services for energy service companies to provide. The outcome of these proceedings may ultimately result in changes to the Company's business, but at this time the Company cannot predict the scope of such changes.

Holding Company. During the second half of 1998, the Company filed applications with various regulatory agencies, including the PSC, Securities and Exchange Commission ("SEC"), Federal Energy Regulatory Commission ("FERC"), and the Nuclear Regulatory Commission ("NRC"), requesting approval of a corporate restructuring including the creation of a holding company. RGS Energy Group, Inc. ("RGS Energy"), a New York corporation, was organized in November 1998 for the purpose of carrying out the restructuring.

Subject to regulatory and shareholder approvals, the Company anticipates forming the holding company structure by mid-1999. FERC approved the Company's application in late November 1998 and the NRC gave approval in December 1998. The remaining regulatory approvals are expected to be received before mid-1999.

At the Company's 1999 Annual Meeting of Shareholders, shareholders will vote on a Plan of Exchange which provides that all of the outstanding shares of RG&E common stock will be exchanged on a share-for-share basis for RGS Energy common stock. Upon consummation of the exchange, RGS Energy will become the parent company of RG&E. Moreover, RG&E intends to transfer its unregulated subsidiaries, Energetix and RGS Development Corporation, to RGS Energy immediately prior to the exchange so that RGS Energy will become the parent company of RG&E and such subsidiaries.

The holding company structure is consistent with provisions of the Competitive Opportunities Settlement.

Unregulated Subsidiaries. It is part of RG&E's financial strategy to seek growth by entering into unregulated businesses. The Settlement allows RG&E to invest up to $100 million in unregulated businesses. The first step in this direction was the formation and operation of Energetix effective January 1, 1998. Energetix is an unregulated subsidiary that brings energy products and services to the marketplace both within and outside of RG&E's regulated franchise territory. Energetix markets electricity, natural gas, oil, gasoline, and propane fuel energy services in an area extending in approximately a 150-mile radius around Rochester.

In August 1998, Energetix announced the acquisition of Griffith Oil Co., Inc. ("Griffith"), the second largest oil and propane distribution company in New York State. Energetix accounted for its acquisition of Griffith as a purchase in the amount of $31,500,000, and purchase accounting adjustments, including goodwill, are reflected in the consolidated financial statements of the Company at December 31, 1998.

Griffith gives Energetix access to 65,000 new customers, 60,000 of which are outside of RG&E's regulated franchise territory. In addition to its current products, Griffith sells electricity, natural gas and other services offered by Energetix to its existing customers. Griffith has approximately 350 employees and operates 16 customer service centers.

Additional information on Energetix's operations (including Griffith) is presented under the headings Operating Revenues, Operating Expenses, and is contained in Note 4 of the Notes to Financial Statements.

During the second quarter of 1998, the Company formed a new unregulated subsidiary, RGS Development Corporation ("RGS Development"). RGS Development was formed to pursue unregulated business opportunities in the energy marketplace. Through December 31, 1998, RGS Development operations have not been material to the Company's results of operations or its financial condition.

Stock Repurchase Plan. By order issued April 24, 1998, the PSC approved a Stock Repurchase Plan providing for the repurchase of Common Stock having an aggregate market value not to exceed $145 million. The Company began the repurchase program in May 1998 and has repurchased 1,507,000 shares of Common Stock for approximately $46.4 million through December 31, 1998. The Company expects to repurchase up to an additional three million shares over the next two years.

PSC Proceeding on Nuclear Generation.

On March 20, 1998, the PSC initiated a proceeding to examine a number of issues raised by a Staff position paper on nuclear generation and the comments received in response to it. In reviewing the Staff paper and parties' comments, the PSC:

1. adopted as a rebuttable presumption the premise that nuclear power should be priced on a market basis to the same degree as power from other sources, with parties challenging that premise having to bear a substantial burden of persuasion,
2. characterized the proposals in the Staff paper as by and large consistent in concept with the PSC's goal of a competitive, market-based electricity industry,
3. questioned Staff's position that would leave funding and other decommissioning responsibilities with the sellers of nuclear power interests and
4. indicated interest in the potential for a New York Nuclear Operating Company (NYNOC) proposal to benefit customers through efficiency gains and directed pursuit of that matter in this nuclear generating proceeding or separately upon the filing of a formal NYNOC proposal.

The Company's potentially strandable assets in nuclear plant could be impacted by the outcome of this proceeding. The initial collaborative conference for this proceeding was held on January 20, 1999. This proceeding is intended to be completed in the fourth quarter of 1999.

FERC Open Access Transmission Orders and Company Filings.

On January 31, 1997, the New York electric utilities filed a "Comprehensive Proposal To Restructure the New York Wholesale Electric Market" with the FERC. As proposed, the existing New York Power Pool (NYPP) will be dissolved and an independent system operator (NYISO) will administer a Statewide open access tariff and provide for the short-term reliable operation of the bulk power system in the State. In addition to proposing a FERC-endorsed NYISO, the proposal calls for creation of a New York Power Exchange and a New York State Reliability Council.

On June 30, 1998, FERC issued an Order that conditionally authorizes the establishment of the NYISO by the member systems of the NYPP. The order addresses areas of governance, standards of conduct and reliability. A NYISO Board of Directors has been formed. FERC has deferred consideration of the unexecuted tariff and agreements filed under Section 205 of the Federal Power Act. FERC noted that these filings will be addressed in a future order, but at this time, no specific date has been set. FERC has also recommended that concerned parties revisit the independent system operator weighted voting distribution relative to governance. On October 23, 1998, the member systems of the NYPP filed a proposed settlement agreement for a comprehensive settlement of governance issues and an explanatory statement of the settlement agreement. The explanatory statement represents the settlement agreement to be in compliance with the Commission's June 30, 1998 Order.

Significant changes to pricing procedures now in effect within NYPP are expected, but it is unclear what effect these changes may have once other regulatory changes in New York State are implemented. 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.

PSC Gas Structuring Policy Statement.

On November 3, 1998, the PSC issued a gas restructuring policy statement ("Gas Policy Statement") announcing its conclusion that, among other things, the most effective way to establish a competitive gas supply market is for gas distribution utilities to cease selling gas. The PSC established a transition process in which it plans to address three groups of issues: (1) individual gas utility plans to implement the PSC's vision of the market; (2) key generic issues to be dealt with through collaboration among gas utilities, marketers, pipelines and other stakeholders, and (3) coordination of issues that are common to both the gas and the electric industries. The Company is in the process of evaluating this Gas Policy Statement and will respond to the specific requirements of the Order. The PSC has encouraged settlement negotiations with each gas utility pertaining to the transition to a fully competitive gas market.

Competition and the Company's Prospective Financial Position.

With PSC approval, the Company has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by 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.

In a competitive electric market, strandable assets would arise when investments made in facilities, or costs incurred to service customers, are not fully recoverable in market-based rates. Estimates of such strandable assets are highly sensitive to assumptions of competitive wholesale market prices. In a competitive natural gas market, strandable assets could arise where customers migrate away from dependence on the Company for full service, leaving the Company with surplus pipeline and storage capacity, as well as natural gas supplies, under contract. A discussion of strandable assets is presented in Note 10 of the Notes to Financial Statements.

At December 31, 1998, the Company believes that its regulatory assets are not impaired and are probable of recovery. The Settlement in the Competitive Opportunities Proceeding does not impair the opportunity of the Company to recover its investment in these assets. However, the PSC issued an Opinion and Order Instituting Further Inquiry on March 20, 1998 to address issues surrounding nuclear generation. The ultimate determination in this proceeding could have an impact on strandable assets and the recovery of nuclear costs. The initial meeting in this Inquiry was held in January 1999 and such a determination is unlikely before year-end.

Rates and Regulatory Matters

GAS PROPOSAL AND INTERIM SETTLEMENT.

In August 1998, prior to issuance of the PSC's Gas Policy Statement (see PSC Gas Restructuring Policy Statement above), RG&E had commenced negotiations with the PSC staff and other parties to develop a comprehensive multi-year settlement of various issues, including rates and the structure of RG&E's gas business. Because the negotiation of a comprehensive settlement is not anticipated to conclude until mid-1999, the parties to the negotiations agreed to an Interim Settlement, effective November 1998 through June 1999, that deals with such issues as rates, transportation and storage capacity costs, assignment of capacity, and retail access. Under the Interim Settlement, which was approved by the PSC on November 9, 1998, base rates for gas service remain frozen at their current levels (which were fixed pursuant to a 1995 Settlement that expired at the end of October 1998). Additionally, RG&E must provide a guaranteed level of benefits to customers from the re-marketing of unneeded transportation and storage capacity, and RG&E must permit marketers serving up to ten percent of retail and aggregated customer annual throughput to do so without mandatory assignment of the corresponding capacity. RG&E is permitted to recover the costs associated with non-assigned capacity from all customers, with certain exceptions.

An Interim Gas Settlement having been reached and the PSC having issued its Gas Policy Statement, RG&E and other parties anticipate proceeding with discussions with PSC Staff based on the Company's August 1998 comprehensive proposal and the PSC's Gas Policy Statement. RG&E's objective is to have a comprehensive final settlement in place prior to July 1, 1999, although no assurance can be given.

Under a March 1996 Order, the PSC permitted RG&E and other gas distribution companies to assign to marketers the pipeline and storage capacity held by RG&E to serve their customers. In its Gas Policy Statement issued in November 1998, the PSC ordered that the mandatory assignment of capacity, permitted by the March 1996 Order, be terminated effective April 1, 1999. According to the Gas Policy Statement, however, the utilities are to be afforded a reasonable opportunity to recover resulting strandable costs, if any.

FLEXIBLE PRICING TARIFF.

Under its flexible pricing tariff for major industrial and commercial electric customers, RG&E may negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Pursuant to the terms of the Settlement under the Competitive Opportunities Proceeding, RG&E will absorb, as it has done since the inception of these rates, the difference between the discounted rates paid under these individual contracts and the rates that would otherwise apply. Approximately 29 percent of all electric sales to customers are made under long-term contracts, primarily to large industrial customers. These contracts represent approximately 45 percent of RG&E's revenues from its commercial and industrial customers.

Liquidity and Capital Resources

Cash flow from operations, external long-term debt financing, and short-term borrowings provided the funds for construction expenditures, funding of unregulated operations, the Company's stock repurchase program, debt reductions, redemption of Preferred Stock and the payment of dividends during 1998. Capital requirements of the Company during 1999 are anticipated to be satisfied from the combination of internally generated funds, short-term credit arrangements, and possibly some external long-term financing.

CAPITAL AND OTHER REQUIREMENTS.

The Company's capital requirements relate primarily to expenditures for energy delivery, including electric transmission and distribution facilities and gas mains and services as well as nuclear fuel, electric production, the repayment of existing debt, and the repurchase of outstanding shares of Common Stock. Construction expenditures in 1998 reflect primarily expenditures for nuclear fuel and upgrading electric transmission and distribution facilities and gas mains. The Company has no plans to install additional baseload generation.

1998 Labor Day Storm. At approximately midnight, Monday morning, September 7, 1998, a severe lightning and windstorm struck the Company's franchise area. The storm damaged the Company's electrical system at several hundred different locations. Several counties within the Company's franchise area were declared State and federal disaster areas.

The Company estimates that initially as many as 100,000 customers lost power due to the storm. On Saturday afternoon, September 12, the Company announced that all power had been restored, in all but a few isolated cases.

In 1998, the Company incurred $7.2 million of costs associated with this storm. Under the Competitive Opportunities Settlement with the PSC, if incremental costs resulting from a "catastrophic event" exceed $2.5 million, such costs could be deferred. The Company has submitted a petition to the PSC for deferral of costs associated with this storm.

Settlement with Co-generator. In May 1998 the Company entered into a Global Settlement Agreement regarding the termination of a power purchase contract with Kamine/Besicorp Allegany L.P. (Kamine). In August 1998 the PSC approved the Global Settlement Agreement, and on December 1, 1998, the Agreement became effective. The Global Settlement Agreement is discussed under Note 10 of the Notes to Financial Statements. Under the terms of the Global Settlement Agreement, the Power Purchase Agreement was terminated in consideration of payment by the Company of $168 million over the next 16 years, without interest, with an initial payment of $10 million. Also, under the terms of the Global Settlement Agreement the Company paid an additional $15 million for the purchase of the Kamine generation facility. The plant may be operated if market conditions warrant and the Company will assess the possible disposition of the plant. The Company does not expect the terms of the Global Settlement Agreement to have any material effect on its earnings. Pursuant to a PSC order approving the terms of the Global Settlement Agreement, regulatory assets have been established by the Company to account for the initial payment, the facility purchase, and future payments. The Company has no other long-term obligations to purchase energy from other cogeneration facilities.

Year 2000 Readiness Information. As the year 2000 (Y2K) approaches, the Company, like most companies, faces potentially serious information and operational systems (computer and microprocessor-based devices) problems because many software applications and embedded systems programs created in the past will not properly recognize calendar dates beginning with the year 2000 or that the year 2000 is a "leap-year".

The Company identified the need to address Y2K issues early and in June 1996 established the Y2K Project (Y2K Project). Resources from across the enterprise have been committed to the Y2K Project. The Company has assigned approximately 40 full-time equivalent people to work on the Y2K Project as well as retaining certain outside consultants to assist in the inventory, assessment, and certification of date-aware devices. The Company expects to fund its Y2K Project internally and estimates it will incur between $10 to $12 million of incremental costs through January 1, 2000, associated with making the necessary modifications identified to date to applications ($11 million) and devices ($1 million). This

projection includes contingencies and replacement systems that may be required and represents 25% of the Corporate Information Technology (IT) budget. The Company has not deferred any other major IT project due to this effort. The Company has incurred approximately $5.3 million of its $12 million total costs through December 31, 1998. The Company is also participating in the Y2K activities of several organizations such as the New York Power Pool, North American Electric Reliability Council, Electric Power Research Institute and others for the development of a network to verify the risks and costs nationally, in the Northeast, in New York State, and in the Company.

The Y2K Project is divided into five primary phases. The first phase is the inventory phase during which applications (both internally developed and vendor developed) and devices (in the generation plants, delivery substations and facilities) are identified and criticality to the business is determined. During the next phase, the assessment phase, the Y2K Readiness of the items is determined. Year 2000 Readiness is defined as a computer system or application that has been determined to be suitable for continued use into the Year 2000 even though the computer system or application is not fully Y2K compliant. The third phase, fixing, is when replacement or remediation of the items is performed. The fourth phase is the testing phase, when the items are functionally verified and date tested. The final phase is the contingency phase when contingency plans will be developed for all critical applications, devices and systems.

To date, the Y2K Project has completed the inventory phase, which was the identification of internally developed applications, devices, vendor applications and critical external parties including customers, suppliers, business partners, government agencies, and financial institutions. The Company will prioritize these critical parties and independently evaluate the most critical of these by various methods, such as mandatory written verification to the Company of their status or testing transfer of information.

The Y2K Project, in the assessment phase, has completed assessment of internally developed applications and critical devices. The Company expects to complete the assessment of critical external parties and vendor applications by the end of the first quarter of 1999. Results of these assessments will be given to the Business Areas for further action.

The fix phase activities of the Y2K project for internally developed applications is 82% complete and for critical devices is 75% complete. The phase is expected to be complete by the end of the first half of 1999. As part of this phase, a recently implemented customer information and billing system is Y2K ready, and starting in April 1998 and continuing through the first half of 1999, the Company is replacing its PC workstations and software with Y2K-ready equipment and software. As facility maintenance outages occur this spring, Y2K critical device replacement/modifications will be performed. Critical devices are an integral part of the system which controls, monitors, and assists in the operation of equipment, machinery, or plant.

Testing of internal applications for Y2K readiness has begun and is 28% complete. Testing of critical applications, devices, and systems will take place primarily in the first half of 1999 and is currently in the initial stages.

The Company has in place a Business Recovery Plan describing alternative processes and procedures to ensure the integrity of its energy and financial systems. The Business Recovery Plan will serve as the basis for Y2K contingency plans. Contingency planning commenced in October 1998 and is expected to be completed by June 1999. The Company will be able to identify its most reasonably likely worst case Y2K contingency scenario by the end of the first quarter of 1999 when it completes the Scenario Risk Analysis phase of contingency planning. Failure to address Y2K issues properly could cause the Company to, among other things, issue inaccurate bills, report inaccurate data, or incur plant outages and/or energy delivery problems.

All activities in support of mission critical systems are expected to be completed by July 1999, as required by the PSC. Likewise, the Company fully expects to meet the July 1999 completion criteria set by the NRC for the Company's Ginna facility.

Energetix, the Company's wholly owned subsidiary, including its recently acquired Griffith, estimates the cost of making the necessary modifications identified to date to be less than $100,000, 50% of which relate to devices and 50% to applications. The cost represents approximately 50% of their IT budget, but no major IT projects have been deferred due to Y2K. Most of its systems, personal computers and operating equipment are less than seven years old. Energetix has identified items that are the most vulnerable to the Y2K problem and is in various stages of assessing, fixing and testing those items. These items are expected to be Y2K-ready by the third quarter of 1999, at which time a Scenario Risk Analysis will be completed. Energetix has a Business Recovery Plan, which will serve as the basis for Y2K contingency planning by the third quarter of 1999 also. Energetix has begun to survey critical third

parties including customers, suppliers, business partners and financial institutions to assess their degree of Y2K readiness and develop contingency plans to ensure the integrity of its operational and financial systems. Energetix will prioritize these critical parties and independently evaluate the most critical of these by various methods, such as mandatory verification of their status or testing transfer of information.

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.

The Company has recorded liabilities to reflect specific issues where remediation activities are currently deemed to be probable and where the cost of remediation can be estimated. Estimates of the extent of the Company's degree of responsibility at a particular site and the method and ultimate cost of remediation require a number of assumptions for which the ultimate outcome may differ from current estimates. While the Company does not anticipate that any adjustment would be material to its financial statements, it is reasonably possible that the result of ongoing and/or future environmental studies or other factors could alter this expectation and require the recording of additional liabilities. The extent or amount of such events, if any, cannot be estimated at this time.

Additional information concerning the Company's environmental matters 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 $49 million in 1996, $152 million in 1997, and $25.5 million in 1998. Included in discretionary redemptions for 1997 and 1998 were over $127 million of tax-exempt securities.

CAPITAL REQUIREMENTS — SUMMARY.

Excluding the Kamine Global Settlement obligations discussed above, capital requirements for the Company over the three-year period 1996 to 1998 and the current estimate of capital requirements through 2001 are summarized in the Capital Requirements table.

CAPITAL REQUIREMENTS

	Actual			Projected		
Type of Facilities	1996	1997	1998	1999	2000	2001
	(Millions of Dollars)					
Electric Property						
Production	$ 57	$ 9	$ 16	$ 20	$ 11	$ 11
Energy Delivery	23	28	41	35	34	19
Subtotal	80	37	57	55	45	30
Nuclear Fuel	16	19	14	16	27	9
Total Electric	96	56	71	71	72	39
Gas Property	17	22	21	18	21	19
Common Property	6	9	21	24	14	11
Total	119	87	113	113	107	69
Carrying Costs						
Allowance for Funds Used During Construction	2	1	1	1	1	1
Total Construction Requirements	121	88	114	114	108	70
Securities Redemptions, Maturities and Sinking Fund Obligations*	67	182	66	10	30	—
Total Capital Requirements	$188	$270	$180	$124	$138	$70

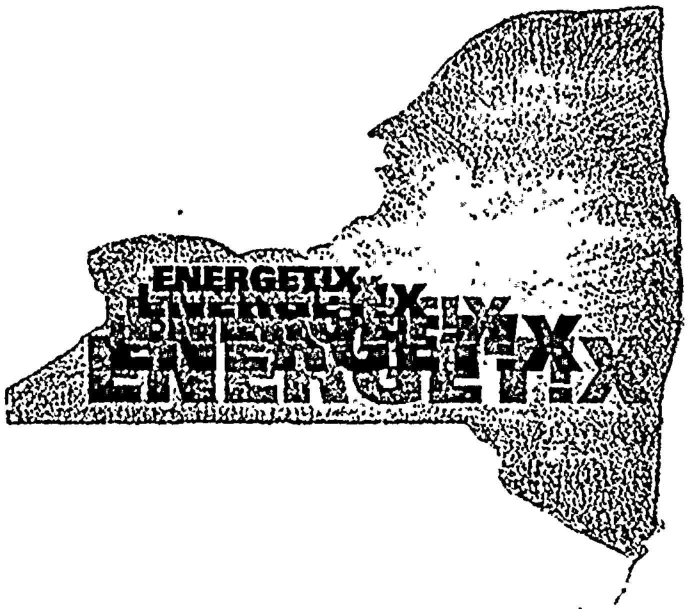
*Excludes prospective refinancings.

The Company's capital expenditures program is under continuous review and could be revised for any number of issues. The Company also may consider, as conditions warrant, the redemption or refinancing of certain outstanding long-term securities.

FINANCING.

On December 22, 1998 the Company issued $50 million of 5.84% First Mortgage Bonds, Designated Secured Medium-Term Notes, Series B. The net proceeds from this financing were used to repay short-term debt.

In September 1998 the Company completed the delivery of $25.5 million of 5.95% New York State Energy Research and Development Authority (NYSERDA) tax-exempt bonds due September 1, 2033. Proceeds were used to redeem $25.5 million of outstanding tax-exempt First Mortgage 8 3/8% Bonds, Series OO, on December 1, 1998.



Included on the Company's consolidated Balance Sheet as of December 31, 1998 is a $24.6 million Promissory Note issued by Energetix in connection with the acquisition of Griffith in August 1998, as discussed under Competition - Unregulated Subsidiaries. This Note is payable in seven annual installments of principal and interest. Also included at year-end 1998 is a $94.8 million liability associated with the $168 million Promissory Note issued in connection with the Kamine Global Settlement Agreement (see Liquidity and Capital Resources - Settlement with Co-Generator). This amount represents the present value at December 31, 1998 of future obligations under the Note assuming a discount rate of 7.5 percent. This Note is secured by a subordinate mortgage on the Company's property. Additional information about these Promissory Notes is discussed in Note 6 of the Notes to Financial Statements.

Under the Company's Performance Stock Option Plan, options for 403,605 shares of Common Stock became exercisable due to Common Stock market price performance during 1997. During 1998, additional options for 43,141 shares were granted, none of which became exercisable. Common Stock shares outstanding increased by 10,883 shares in 1997 and 23,466 shares in 1998 as a result of those options which were actually exercised. These were the only shares of Common Stock issued by the Company during 1997 and 1998.

In 1998 the Company began funding a stock repurchase program and investments in unregulated businesses as discussed under Competition.

Capital requirements during 1999 are anticipated to be satisfied primarily from the combination of internally generated funds and the use of short-term credit arrangements with some external long-term financing possible during the year. The Company may refinance long-term securities obligations during 1999 depending on prevailing financial market conditions.

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. For information with respect to short-term borrowing arrangements and limitations, see Note 9 of the Notes to Financial Statements. As financial market conditions warrant, the Company may also, from time to time, redeem higher-cost senior securities.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1998 to 1997 and 1997 to 1996. The Notes to Financial Statements contain additional information.

INCOME STATEMENT CHANGES.

Operating revenues have been reclassified into three components. Two of them, electric operating revenues and gas operating revenues, include all regulated and unregulated sales of electricity and gas, respectively. The third, other operating revenues, includes mainly sales from Griffith, as well as other energy products. Unregulated fuel expenses and unregulated operating and maintenance expenses excluding fuel reflect certain operating expenses of Energetix.

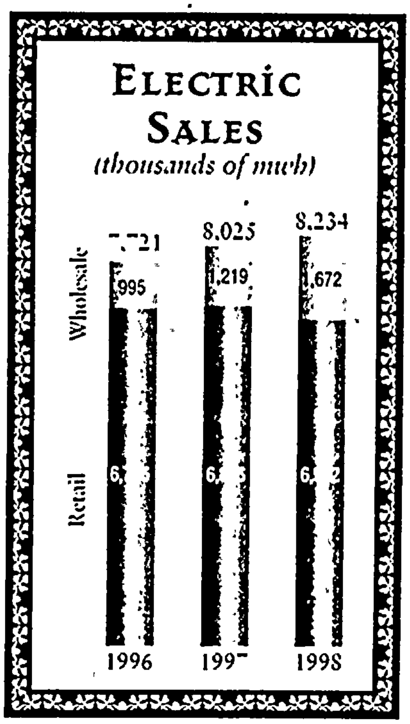
OPERATING REVENUES AND SALES—SUMMARY.

Total Company operating revenues in 1998 were $1,034 million, or 0.2% below 1997. Revenues in 1998 reflect unregulated operations as discussed below. For 1998, a decrease in electric base rates and lower therm sales of gas due to milder weather during the heating season were partially offset by higher wholesale electric sales. In 1997, operating revenues were lower than 1996 with the effect of RG&E's electric base rate decreases in July 1996 and 1997 and lower therm sales of gas due to milder weather partially offset by higher electric kilowatt-hour sales.

Unregulated Operating Revenues and Sales. Included in total operating revenues for 1998 are $10.6 million of electric and gas operating revenues received by Energetix and $71.2 million of Griffith operating revenues.

During 1998, Energetix derived 99% of its revenues (excluding Griffith revenues) from electric and gas sales. The balance of revenues was derived from ServiceCare, the appliance warranty service. Electric sales do not reflect significant seasonal variances. Gas revenues, however, are subject to seasonal fluctuations due to the dependence on spaceheating sales during the heating season. While Energetix was formed January 1, 1998, its first revenues were not received until April of 1998. As a result, 1998 gas revenues reflect only a small amount of spaceheating sales.

During 1998 and since its acquisition by Energetix in August, Griffith derived 97% of its total revenues from distillates (heating oil, kerosene, and diesel), and gasoline sales. The balance of revenues was mainly derived from propane, servicing and motor lubricant sales. Griffith separates the business into three general segments: retail or residential, wholesale which consists of large commercial and reseller accounts, and dealers or service stations. For distillates and propane sales, Griffith experiences seasonal fluctuations due to the dependence on spaceheating sales during the heating season. In addition, gasoline sales reflect seasonal fluctuations due to increased consumer driving during the warmer months.



Regulated Operating Revenues and Sales. 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. Compared to a year earlier, weather in the Company's service area was 13.6 percent warmer during the first three months of 1998 and 18.1 percent warmer for the entire year on a calendar month heating degree day basis. Likewise, weather during 1997 was 1.2 percent warmer than 1996 on a calendar month heating degree day basis. The Company has no weather normalization clause in its gas tariff; therefore, abnormal weather variations will have a more pronounced effect on gas revenues. Warmer summer weather during 1998 boosted electric energy sales to meet the demand for air conditioning usage,

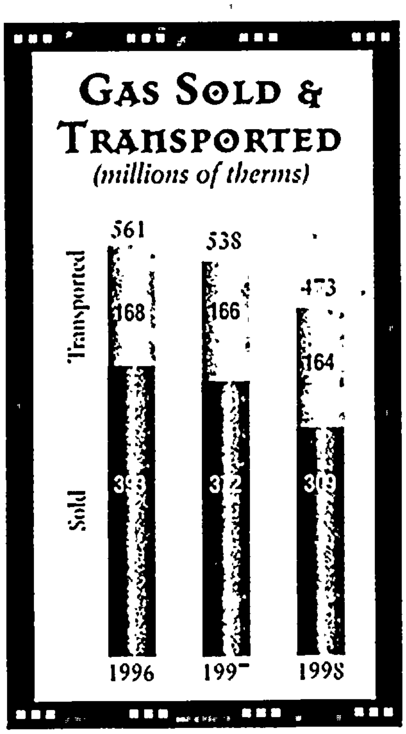
compared to the cool 1997 summer weather conditions. On a cooling degree day basis, weather in 1998 was 62 percent warmer than 1997, while in contrast, the 1997 weather was approximately 27 percent cooler than 1996.

Compared with a year earlier, kilowatt-hour sales of energy to retail customers were down 3.6 percent in 1998, following a 1.2 percent increase in 1997. Commercial and industrial sales were down in 1998 due, in part, to the opening of the electric market under terms of the Competitive Opportunities Settlement. Reported retail sales are depressed as former RG&E customers choose an alternative energy supplier as permitted under the terms of the Competitive Opportunities Settlement. RG&E, however, also sells electric energy, as well as distribution services, to qualified energy marketers in its franchise territory, which has the effect of increasing electric wholesale sales and revenues as discussed in the following paragraph. Partially offsetting the decline in electric sales in 1998 to retail customers was the increased demand for air-conditioning usage caused by the warmer summer weather. In contrast, cooler summer weather had a negative impact on kilowatt-hour sales in 1997.

Under its Energy Choice Program, RG&E on July 1, 1998 began selling electricity and distribution services to qualified energy marketers to serve their retail customers as permitted by the terms of the Competitive Opportunities Settlement. Electric sales to energy marketers, including the Company's unregulated subsidiary Energetix, totaled 174,676 megawatt-hours in 1998. Revenue from these energy marketers for electricity and distribution services totaled $15.0 million and is included in electric operating revenues.

Fluctuations in revenues from electric sales to other utilities are generally related to RG&E's customer energy requirements, the wholesale energy market, availability of transmission, and the availability of electric generation from RG&E's facilities. Revenues from electric sales to other utilities were $29.0 million in 1998, an increase of $8.1 million over 1997. These revenues are included in electric operating revenues. The higher revenues in 1998 reflect a favorable wholesale market and increased marketing of available capacity. Revenues in 1997 from electric sales to other utilities also rose compared with a year earlier due to increased sales resulting from greater availability of RG&E's combined nuclear and fossil generation, a favorable wholesale market in the second half of the year, and increased marketing of available capacity.

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 16.4 million dekatherms in 1998 and 16.6 million dekatherms in 1997. These purchases by eligible customers have caused decreases in the Company's retail gas customer revenues, with offsetting decreases in purchased gas expenses and, 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, are the same as the rates charged the Company's retail gas service customers. Moreover, under the current regulatory environment, the Company does not earn a return on the gas commodity it acquires for distribution. Gas supplies transported in this manner are not included in Company therm sales, depressing reported gas sales to non-residential customers.



Therms of gas sold and transported were down 12.1 percent in 1998, after declining four percent in 1997. 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 decreased about 1.5 percent in 1998 over 1997, while non-residential sales, including gas transported, would have increased approximately two percent in 1998. The average use per residential gas customer, when adjusted for normal weather conditions, showed a modest decrease in 1998 and 1997.

Fossil Unit Status.

On January 21, 1998, the Company announced the retirement of Beebee Station by mid-1999. Factors such as the plant's age, lack of a rail/coal delivery system and more stringent clean air regulations made the plant uneconomical in the developing competitive generation business. The retirement of Beebee Station is not expected to have a material effect on the Company's financial, position or results of operations. The plant will be fully depreciated at the time of retirement. The Competitive Opportunities Settlement provides that all prudently incurred incremental costs associated with the retirement and decommissioning of the plant are recoverable through the Company's distribution access rates. The electric capacity and energy currently provided by the plant are expected to be replaced in the energy markets as needed.

The Company and Niagara Mohawk Power Corporation (Niagara Mohawk) have entered into an agreement dated June 8, 1998 (Sale Agreement) whereby the Company's 24% ownership interest in the Oswego Generating Facility Unit 6 (Oswego 6) non-nuclear generating facility was included in the bidding process for the sale of Niagara Mohawk's non-nuclear generation pursuant to Niagara Mohawk's electric restructuring agreement approved by the PSC. Niagara Mohawk owns the remaining 76% of Oswego 6.

The Sale Agreement provides for the allocation of proceeds and liabilities pertaining to the Oswego 6 facility in accordance with the ownership interests of the Company and Niagara Mohawk. For purposes of the Sale Agreement, the Company's 24% interest in the Oswego 6 facility has been deemed equivalent to a 12% interest in the entire Oswego Generation Facility, which consists of Oswego 6, another operational unit, Oswego 5, that is virtually identical to Oswego 6, and four older, non-operational units, Oswego 1-4. The Sale Agreement has been approved by the PSC. The bidding process continued into January 1999. The Company cannot predict whether Oswego 6 will be sold or at what price. Under the terms of the Competitive Opportunities Settlement, a gain for RG&E on such sale would be shared between RG&E and its customers. With regard to a loss on such sale, the Settlement acknowledges an intent that RG&E will be permitted to recover such losses through distribution rates during the term of the Settlement. Future rate treatment is to be consistent with the principle that RG&E is to have a reasonable opportunity to recover such costs. The electric capacity and energy currently provided by the plant are expected to be replaced in the energy markets as needed. The book value of the Company's interest in Oswego 6 at December 31, 1998 was $53.8 million.

Operating Expenses—Summary.

Changes in fuel expenses for both comparison periods reflect primarily the availability of Company generating facilities, variations in sales of energy, and weather effects on gas purchased for resale during the heating season. For the 1998 comparison period, fuel expenses also reflect unregulated operations. Non-fuel operating expense was down in 1998 reflecting lower federal income taxes and a drop in other operating expenses (see Operations Excluding Fuel Expenses), partially offset by recognition of unregulated non-fuel operating expense. For 1997, compared to a year earlier, non-fuel operating expense was up due to higher depreciation expense, partially offset by lower local and State taxes.

Unregulated Operating Expenses. Unregulated fuel expenses in 1998 as shown on the Income Statement reflect mainly the cost of purchased fuel for Griffith operations since its acquisition by Energetix. Unregulated non-fuel operating expenses reflect primarily payroll expenses, fleet expenses for Griffith, and general and administrative expenses.

Regulated Operating Expenses.

Energy Costs - Electric. Higher fuel expense for electric generation in both comparison periods reflects increased generation to support higher electric sales. For the 1998 comparison period, increased fuel expense also reflects relatively more generation from the Company's costlier fossil-fueled units. A fuel cost adjustment clause was eliminated effective July 1, 1996. Company shareholders are assuming the full benefits and detriments realized from actual electric fuel costs and generation mix compared with PSC-approved forecast amounts.

RG&E 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. Increased availability and efficiencies following the 1996 installation of new steam

generators at the Ginna nuclear plant resulted in lower kilowatt-hour purchases of electricity in 1997 which led to a decline in purchased electric power expense. In 1998, purchased electric expense also decreased, reflecting greater availablity of the Company's generating facilities.

Energy Management and Costs - Gas. RG&E acquires gas supply and transportation capacity based on its requirements to meet peak loads which occur in the winter months. RG&E is committed to transportation capacity on the Empire State Pipeline (Empire) and the CNG Transmission Corporation (CNG) pipeline systems, as well as to upstream pipeline transportation and storage services. The combined CNG and Empire transportation capacity is adequate to meet RG&E's current requirements.

For the 1998 and 1997 comparison periods, gas purchased for resale expense declined driven by a reduced volume of purchased gas resulting from a warmer heating season.

Operations Excluding Fuel Expenses. For the 1998 comparison period, operations less fuel expenses declined, reflecting decreased expense of $5.3 million associated with uncollectible accounts and a $7.9 million drop in welfare expenses due to the performance of pension assets (see Note 3 to the Notes to Financial Statements). Partially offsetting these lower costs were increased payroll costs of $2.2 million. For the 1997 comparison period, the increase in operations excluding fuel expenses reflects mainly higher outside services expenses ($6.1 million), recognition of obsolete and unproductive materials inventory ($3.0 million), and storm costs ($1.7 million) partially offset by $3.9 million of lower payroll costs and decreased expense of $2.0 million associated with uncollectible accounts. The recognition of obsolete materials was driven by the planned relocation of the Company's warehouse. The decrease in the uncollectable accounts expense is driven by the increased level of collection activity in the last two years.

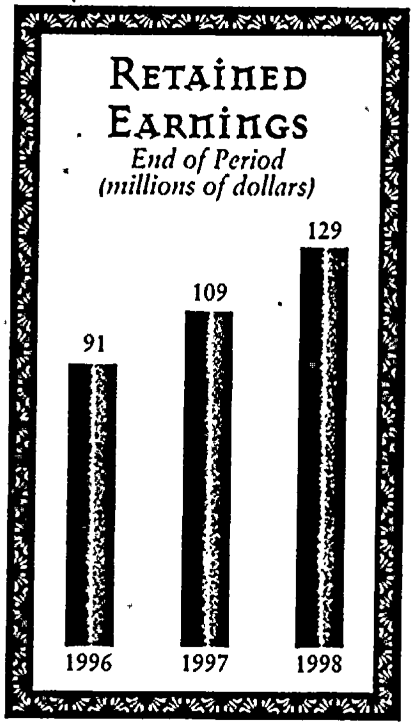
For the 1997 comparison period, the increase in depreciation and amortization expense reflects primarily results from depreciation of the Ginna nuclear plant steam generators, which were replaced in 1996 and recovery of increased nuclear decommissioning expense of approximately $3.2 million per quarter beginning July 1, 1996. The higher decommissioning expense reflects an increase in the estimated cost of decommissioning as recognized in rates for Ginna Station and Nine Mile Two. Depreciation and amortization expense in 1998 includes $1.1 million for unregulated operations, but remained relatively flat compared to 1997 due to the completion of depreciation expense on certain fully depreciated computer equipment.

Taxes Charged To Operating Expenses. Local, State and other taxes declined in 1998 reflecting mainly lower State revenue taxes due to decreased revenues. This decline was partially offset by an additional $1.5 million of local and State taxes associated with unregulated operations. The decrease in local and State taxes for 1997 reflects mainly lower property taxes due to decreases in assessments and/or rates and lower state revenue taxes due to decreases in revenues and the New York State revenue tax surcharge rate.

The decrease in federal income tax in 1998 reflects decreased earnings and in 1997 reflects mainly the reversal of a prior provision for the in-service date of Nine Mile Two as a result of an agreement reached with the Internal Revenue Service.

Other Statement of Income Items. For the 1998 comparison period, the variation in non-operating federal income tax reflects variances in non-operating earnings before federal income-taxes, as well as a $1.7 million reserve for deferred taxes subsequent to a review of the historic balances.

The change in Other Income and Deductions, Other-net in 1998 reflects the recognition of income due to the reversal of certain deferred credits in accordance with the Competitive Opportunities Settlement. In prior years, the PSC had required the Company to establish deferred credits to account for certain pension and other post-employment benefit charges and Nine Mile Two operating and maintenance expenses. In 1998, these deferred credits totaling $17.4 million were eliminated consistent with the terms of the Settlement and discussions with the PSC. An amount of $8.8 million associated with certain pension charges was reflected on the Company's books in the first quarter of 1998, after the Company received the written order associated with the Competitive Opportunities Settlement. An amount of $6.0 million associated with certain Nine Mile Two operating and maintenance expenses was reflected ratably over each of the four quarters of 1998, consistent with Nine Mile Two accounting practices. The remainder associated with certain other post-employment benefits was reflected in the second quarter of 1998, after the Company had concluded discussions with the PSC. The Company does not have any deferred credits which are subject to PSC Orders which would permit the recognition of any significant credits to income in the future. This income was partially offset by



expenses associated with the gas interim settlement agreement. Other (Income) and Deductions, Other—net changed in 1997 due mainly to recognition of expense associated with management performance awards and the Company's Performance Stock Option Plan.

Both mandatory redemptions and the optional redemptions of certain higher-cost long-term debt have helped to reduce long-term debt interest expense over the three-year period 1996-1998. Other interest decreased in 1998 due to lower miscellaneous interest charges on pension and other post-employment benefits. This decline was partially offset by an additional $1.0 million of interest expense associated with unregulated operations. Compared to the prior year, the average RG&E short-term debt outstanding was up in 1998 and nearly unchanged in 1997.

The mandatory redemption of the Company's 7.55% Preferred Stock, Series T, caused Preferred Stock dividends to decrease in 1998. Preferred Stock dividends also decreased in 1997 due to the Company's discretionary redemption in April 1997 of its 7.50% Preferred Stock, Series N and the mandatory sinking fund redemption of its 7.45% Preferred Stock, Series S in September.

Dividend Policy

The level of future cash dividend payments on Common Stock will be dependent upon the Company's future earnings, its financial requirements, and other factors. The Company's Certificate of Incorporation provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company.

OFFICER APPOINTMENT

Paul C. Wilkens was promoted to the position of senior vice-president of generation. Most recently he had been director of gas services, and has extensive experience in electric generation and was once director of nuclear engineering services.

Financial Reports

Report of Independent Accountants

PRICEWATERHOUSECOOPERS

1100 Bausch & Lomb Place
Rochester, New York 14604-2705
January 20, 1999

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, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 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.

PricewaterhouseCoopers LLP

Consolidated Statement of Income

(Thousands of Dollars) Year Ended December 31	1998	1997*	1996*
Operating Revenues			
Electric	$ 687,970	$ 700,329	$ 707,768
Gas	275,177	336,309	346,279
Other	71,215	—	—
Total Operating Revenues	1,034,362	1,036,638	1,054,047
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	53,954	47,665	40,938
Purchased electricity	27,024	28,347	46,484
Gas purchased for resale	155,497	196,579	202,297
Unregulated fuel expenses	60,001	—	—
Total Fuel Expenses	296,476	272,591	289,719
Operating Revenues Less Fuel Expenses	737,886	764,047	764,328
Other Operating Expenses			
Operations and maintenance excluding fuel expenses	301,625	315,109	313,157
Unregulated operating and maintenance expenses excluding fuel	13,257	—	—
Depreciation and amortization	116,122	116,522	105,614
Taxes—local, state and other	118,337	121,796	126,868
Federal income tax	61,385	65,279	69,501
Total Other Operating Expenses	610,726	618,706	615,140
Operating Income	127,160	145,341	149,188
Other (Income) and Deductions			
Allowance for other funds used during construction	(408)	(351)	(684)
Federal income tax	516	(3,704)	(3,450)
Other, net	(13,181)	3,308	(712)
Total Other (Income) and Deductions	(13,073)	(747)	(4,846)
Interest Charges			
Long term debt	42,590	44,615	48,618
Other, net	4,158	6,676	9,328
Allowance for borrowed funds used during construction	(653)	(563)	(1,423)
Total Interest Charges	46,095	50,728	56,523
Net Income	94,138	95,360	97,511
Dividends on Preferred Stock	4,842	5,805	7,465
Earnings Applicable to Common Stock	$ 89,296	$ 89,555	$ 90,046
Earnings per Common Share—Basic	$ 2.32	$ 2.30	$ 2.32
Earnings per Common Share—Diluted	$ 2.31	$ 2.30	$ 2.32

Consolidated Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31	1998	1997*	1996*
Balance at Beginning of Period	$109,313	$ 90,540	$ 70,330
Add			
Net Income	94,138	95,360	97,511
Adjustment Associated with Stock Options Exercised	(72)	—	—
Adjustment Associated with Stock Redemptions	(126)	(846)	—
Total	203,253	185,054	167,841
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock—at required rates	4,842	5,805	7,465
Common stock	68,927	69,936	69,836
Total	73,769	75,741	77,301
Balance at End of Period	$129,484	$109,313	$ 90,540
Cash Dividends Declared per Common Share	$ 1.80	$ 1.80	$ 1.80

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

Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1998	1997
Assets		
Utility Plant		
Electric	$2,477,077	$2,439,108
Gas	435,318	416,989
Common	158,038	134,938
Nuclear fuel	256,562	243,042
	3,326,995	3,234,077
Less: Accumulated depreciation	1,640,645	1,510,074
Nuclear fuel amortization	222,830	204,294
	1,463,520	1,519,709
Construction work in progress	98,554	74,018
Net Utility Plant	1,562,074	1,593,727
Current Assets		
Cash and cash equivalents	6,523	25,405
Accounts receivable, net of allowance for doubtful accounts: 1998—$26,554; 1997—$26,926	89,291	104,781
Unbilled revenue receivable	37,922	48,438
Materials, supplies and fuels	43,024	39,929
Prepayments	25,950	23,818
Other current assets	253	—
Total Current Assets	202,963	242,371
Intangible Assets		
Goodwill	14,681	—
Other intangible assets	6,381	—
Total Intangible Assets	21,062	—
Deferred Debits and Other Assets		
Nuclear generating plant decommissioning fund	183,502	132,540
Nine Mile Two deferred costs	29,258	30,309
Unamortized debt expense	17,241	16,943
Other deferred debits	18,531	20,411
Regulatory assets	416,320	231,988
Other assets	1,984	—
Total Deferred Debits and Other Assets	666,836	432,191
Total Assets	$2,452,935	$2,268,289

(Thousands of Dollars) At December 31	1998	1997*
Capitalization and Liabilities		
Capitalization		
Long term debt—mortgage bonds	$ 510,002	$ 485,434
—promissory notes	248,224	101,900
Preferred stock redeemable at option of Company	47,000	47,000
Preferred stock subject to mandatory redemption	25,000	35,000
Common shareholders' equity:		
Common stock ($5 par, 37,378,813 shares at December 31, 1998 and 38,862,347 shares at December 31, 1997)	699,730	699,031
Retained earnings	129,484	109,313
	829,214	808,344
Less: Treasury stock at cost (1,507,000 shares)	46,433	—
Total Common Shareholders' Equity	782,781	808,344
Total Capitalization	1,613,007	1,477,678
Long Term Liabilities		
Nuclear waste disposal	87,566	83,261
Uranium enrichment decommissioning	12,197	13,465
Site remediation	24,157	13,626
Total Long Term Liabilities	123,920	110,352
Current Liabilities		
Long term debt due within one year	427	30,000
Preferred stock redeemable within one year	10,000	10,000
Short term debt	57,000	20,000
Accounts payable	52,454	53,195
Dividends payable	17,937	18,791
Equal payment plan	11,025	8,935
Other	34,526	34,770
Total Current Liabilities	183,369	175,691
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	326,972	344,969
Pension costs accrued	58,677	67,361
Kamine deferred costs	65,799	—
Post employment benefits internal reserve	42,909	32,190
Other	38,282	60,048
Total Deferred Credits and Other Liabilities	532,639	504,568
Commitments and Other Matters	—	—
Total Capitalization and Liabilities	$2,452,935	$2,268,289

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

Consolidated Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31	1998	1997*	1996*
Cash Flow from Operations			
Net income	$ 94,138	$ 95,360	$ 97,511
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	134,259	133,942	121,824
Deferred fuel	(3,565)	489	(6,501)
Deferred income taxes	(9,141)	(10,064)	6,391
Allowance for funds used during construction	(1,061)	(914)	(2,107)
Unbilled revenue, net	10,516	4,823	10,908
Stock option plan, net	99	2,399	—
Nuclear generating plant decommissioning fund	(20,827)	(20,331)	(11,732)
Payment to Kamine	(17,790)	—	—
Pension costs accrued	(15,818)	(3,398)	(2,494)
Post employment benefit internal reserve	10,719	6,189	6,626
Provision for doubtful accounts	(372)	5,078	4,987
Changes in certain current assets and liabilities:			
Accounts receivable	27,549	3,049	3,228
Materials, supplies and fuels	141	(41)	(1,238)
Taxes accrued	(1,448)	347	(13,944)
Payroll accrued	54	433	17
Accounts payable	(7,031)	3,733	(3,116)
Other current assets and liabilities, net	(817)	6,911	(5,203)
Other, net	(4,699)	6,847	(3,931)
Total Operating	194,906	234,852	201,226
Cash Flow from Investing Activities			
Net additions to utility plant	(129,286)	(84,068)	(114,274)
Acquisition, net of cash	(30,977)	—	—
Other, net	484	(1)	9,204
Total Investing	(159,779)	(84,069)	(105,070)
Cash Flow from Financing Activities			
Proceeds from:			
Sale/Issuance of common stock	586	272	8,612
Issuance of long term debt	99,422	101,900	—
Short term borrowings, net	30,500	6,000	14,000
Retirement of long term debt	(55,500)	(151,568)	(67,332)
Retirement of preferred stock	(10,000)	(30,000)	—
Dividends paid on preferred stock	(5,031)	(6,366)	(7,465)
Dividends paid on common stock	(69,592)	(69,933)	(69,657)
Payment for treasury stock	(46,433)	—	—
Equal payment plan	2,090	3,385	4,273
Other, net	(51)	(369)	(1,407)
Total Financing	(54,009)	(146,679)	(118,976)
Increase (Decrease) in cash and cash equivalents	$ (18,882)	$ 4,104	$ (22,820)
Cash and cash equivalents at beginning of year	$ 25,405	$ 21,301	$ 44,121
Cash and cash equivalents at end of year	$ 6,523	$ 25,405	$ 21,301

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31	1998	1997	1996
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 43,793	$ 50,681	$ 55,545
Income taxes paid	$ 75,600	$ 70,500	$ 76,890

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

NOTE I

Summary of Accounting Principles

GENERAL.

The Company supplies regulated electric and gas services wholly within the State of New York. The unregulated portion of the Company provides products and services as discussed in Note 4. 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 Energetix and Energyline. All intercompany balances and transactions have been eliminated. Energetix financial statements are consolidated with its wholly-owned subsidiary Griffith.

Energyline was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. In late 1996, Energyline sold its investment in the Empire State Pipeline.

During the second quarter of 1998, the Company formed a new unregulated subsidiary, RGS Development Corporation ("RGS Development"). RGS Development was formed to pursue unregulated business opportunities in the energy marketplace. Through December 31, 1998, RGS Development operations have not been material to the Company's results of operation or its financial condition.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES.

GOODWILL AND OTHER INTANGIBLE ASSETS.

Goodwill presented on the consolidated balance sheet, represents the excess of cost over the net tangible and identifiable intangible assets of acquired businesses. It is stated at cost and is amortized, principally on a straight-line basis, over the estimated future periods to be benefited (20 years). On an annual basis the Company reviews the recoverability of goodwill based primarily upon an analysis of undiscounted cash flows from the acquired businesses. Other intangible assets include dealer improvements and are being amortized over varying periods. Accumulated amortization amounted to $0.7 million at December 31, 1998.

ACQUISITIONS.

In August 1998, Energetix announced the acquisition of Griffith Oil, Co., Inc. ("Griffith"), for $31.5 million. Griffith sells oil, propane, electricity, gasoline, natural gas and other services offered by Energetix to its existing customers. The acquisition was accounted for as a purchase resulting in goodwill as reflected on the consolidated financial statements. The principal assets acquired were vehicles, tanks, pumps, buildings and commodity inventory.

Note 1 continued on page 30

(continued from page 29)

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.

Through June 30, 1996, tariffs for electric service included fuel cost adjustment clauses which adjusted the rates monthly to reflect changes in the actual average cost of fuels. Beginning July 1, 1996, the electric fuel adjustment clause was eliminated in connection with a rate settlement agreement with the PSC.

The Company continues to use 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 (AFUDC) approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. 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 rate approved by the PSC for purposes of computing AFUDC was 5.0% during the three-year period ended December 31, 1998. 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 regulated depreciation provision of 3.2% in the three-year period ended December 31, 1998. The annual depreciation provision of Energetix is 8.0% for 1998.

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.

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. The Company has no other debt or equity securities.

FINANCIAL/COMMODITY INSTRUMENTS.

The Company periodically enters into agreements to minimize price risks for natural gas in storage. Gains or losses resulting from these agreements are deferred until the corresponding gas is withdrawn from storage and delivered to customers. The Company primarily enters into forward contracts for natural gas through its gas broker.

Griffith is in the business of purchasing various petroleum-related commodities for resale to its customers. In order to manage the risk associated with market price fluctuations Griffith enters into various exchange-traded futures and option contracts and over-the-counter contracts with third parties. The commodity instruments are designated at the inception as a hedge where there is a direct relationship to the price risk associated with the company's inventory or future purchases and sales of commodities used in the company's operation. These contracts are closely monitored on a daily basis to manage the price risk associated with the company's inventory and future product commitments. All hedge contracts are accounted for under the deferral method with gains and losses from the hedging activity included in the cost of sales as inventories are sold or as the hedge transaction occurs. Commodity instruments not designated as effective hedges are marked to market at the end of the reporting period, with the resulting gains or losses recognized in cost of sales. As of December 31, 1998 the Company had net deferred gains on open hedge contracts of $0.7 million.

RESEARCH AND DEVELOPMENT COSTS.

Research and Development costs were charged to expense as incurred. Expenditures for the years 1998, 1997, and 1996 were $3.4 million,$4.5 million and $4.9 million respectively.

ENVIRONMENTAL REMEDIATION COSTS.

The Company accrues for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study.

Such accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

MATERIALS, SUPPLIES AND FUELS.

Materials and supplies inventories are valued at the lower of cost or market using the first-in, first-out method. Regulated fuel inventories are valued at average cost. Griffith fuel inventories are valued at the lower of cost or market.

STOCK-BASED COMPENSATION.

Financial Accounting Standards Board Statement No. 123 (SFAS-123), Accounting for Stock-Based Compensation, was adopted by the Company in the first quarter of 1996. It recommends the use of a fair value based method of accounting for compensation costs associated with stock-based compensation. The Company currently has Stock Appreciation Rights plans covering certain employees and directors. For these plans, the Company's accounting policy has been to use a fair value method of computing periodic compensation expense. SFAS-123 was applied to the valuation of the 1996 Performance Stock Option Plan (PSOP), which became effective on January 22, 1997. The aggregate amount charged to expense as a result of these plans for the years 1998, 1997 and 1996 approximates $5.9 million, $8.2 million and $1.0 million respectively. Additional information on the PSOP is included in Note 8.

EARNINGS PER SHARE.

SFAS-128, Earnings Per Share, was adopted by the Company in the fourth quarter of 1997. This statement replaces the presentation of primary Earnings Per Share with Basic Earnings Per Share, and also requires presentation of Diluted Earnings Per Share. Basic Earnings Per Share (EPS) is computed by dividing income available to common shareholders by the weighted average number

Note 1 continued on page 32

(continued from page 31)

of common shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the earnings of the Company.

The following table illustrates the calculation of both Basic and Diluted EPS for the year ended December 31,:

(thousands of dollars except per share amounts)	1998	1997
Basic EPS:		
Net Income	$94,138	$95,360
Less:		
Preferred Stock Dividends	(4,842)	(5,805)
Income available to Common Shareholders	$89,296	$89,555
Shares	38,462	38,853
Per-Share Amount	$2.32	$2.30
Diluted EPS:		
Effect of Dilutive Securities Stock Option Plan	138	56
Income available to Common Shareholders plus assumed conversions	$89,296	$89,555
Shares	38,600	38,909
Per-Share Amount	$2.31	$2.30

There were no dilutive shares in 1996.

Comprehensive Income.

There were no items of comprehensive income during the year ended December 31, 1998; therefore, net income is equivalent to total comprehensive income.

New Accounting Pronouncements.

Financial Accounting Standards Board Statement No. 131 (SFAS-131), Disclosures about Segments of an Enterprise and Related Information, was adopted by the Company in 1998. SFAS-131 supersedes SFAS-14, Financial Reporting for Segments of a Business Enterprise. The adoption of SFAS-131 did not affect the Company's operating results. Note 4 contains specific information and disclosures related to the Company's Regulated Electric, Regulated Gas and Unregulated segments.

Reclassifications.

Certain amounts in the prior years' financial statements were reclassified to conform with current year presentation.

NOTE 2

Federal Income Taxes

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

(Thousands of Dollars)	1998	1997	1996
Charged (Credited) to operating expense:			
Current	$70,541	$69,812	$65,757
Deferred	(9,156)	(4,533)	3,744
Total	61,385	65,279	69,501
Charged (Credited) to other income:			
Current	(1,614)	1,828	(6,097)
Deferred	4,562	(3,100)	5,079
Deferred investment tax credit	(2,432)	(2,432)	(2,432)
Total	516	(3,704)	(3,450)
Total Federal income tax expense	$61,901	$61,575	$66,051

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 at the statutory tax rate of 35%.

(Thousands of Dollars)	1998	1997	1996
Net Income	$ 94,138	$ 95,360	$ 97,511
Add: Federal income tax expense	61,901	61,575	66,051
Income before Federal income tax	$156,039	$156,935	$163,562
Computed tax expense at statutory tax rate	$ 54,614	$ 54,927	$ 57,247
Increases (decreases) in tax resulting from:			
Difference between tax depreciation and amount deferred	9,366	10,772	10,796
Deferred investment tax credit	(2,432)	(2,432)	(2,432)
Miscellaneous items, net	353	(1,692)	440
Total Federal income tax expense	$ 61,901	$ 61,575	$ 66,051

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

(Thousands of Dollars)	1998	1997	1996
Nuclear decommissioning	$(24,849)	$(20,807)	$(17,880)
Accelerated depreciation	214,521	216,704	213,907
Deferred investment tax credit	25,768	27,981	29,562
Depreciation previously flowed through	146,953	157,538	169,562
Pension	(20,161)	(23,166)	(24,570)
Other	(15,260)	(13,281)	(553)
Total	$326,972	$344,969	$370,028

SFAS-109 "Accounting for Income Taxes" 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, 1998 and 1997 was $148 million and $160 million, respectively. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

NOTE 3

Pension and Other Postretirement Benefit Plans

The following table shows reconciliations of the domestic pension plan and other postretirement plan benefits as of December 31, 1998 and 1997:

(Millions)	Pension Benefits		Other Benefits	
	1998	1997	1998	1997
Change in benefit obligation				
Benefit obligation at beginning of year	$ 499.3	$ 480.2	$ 89.0	$ 79.1
Service cost	7.0	6.2	1.1	0.9
Interest cost	32.9	33.1	6.0	5.8
Plan Amendments	0.0	0.0	4.3	0.0
Actuarial loss	10.6	13.1	2.7	7.2
Benefits paid	(33.0)	(33.3)	(4.1)	(4.0)
Benefit obligation at end of year	$ 516.8	$ 499.3	$ 99.0	$ 89.0
Change in plan assets				
Fair value of plan assets at beginning of year	$ 638.4	$ 567.1	$ 0.0	$ 0.0
Actual return on plan assets	100.0	104.0	0.0	0.0
Company contribution	0.9	0.5	4.1	4.0
Benefits paid	(32.9)	(33.2)	(4.1)	(4.0)
Fair value of plan assets at end of year	$ 706.4	$ 638.4	$ 0.0	$ 0.0
Funded status	$ 189.5	$ 139.1	$ (99.0)	$ (89.0)
Unrecognized actuarial loss	(259.4)	(219.0)	11.2	8.4
Unrecognized prior service cost	9.9	10.7	12.6	8.9
Unrecognized net transition obligation (asset)	1.3	1.8	32.3	39.5
Accrued benefit cost	$ (58.7)	$ (67.4)	$ (42.9)	$ (32.2)
Weighted-average assumptions as of December 31				
Discount rate	6.50%	6.75%	6.50%	6.75%
Expected return on plan assets	8.50%	8.50%	—	—
Rate of compensation increase	5.00%	5.00%	—	—

(Millions)	Pension Benefits			Other Benefits		
	1998	1997	1996	1998	1997	1996
Components of net periodic benefit cost						
Service cost	$ 7.0	$ 6.2	$ 7.4	$ 1.1	$ 0.9	$ 1.0
Interest cost	32.9	33.1	33.4	6.0	5.8	5.4
Expected return on plan assets	(44.8)	(39.6)	(37.2)	0.0	0.0	0.0
Unrecognized transition obligation	0.5	0.5	0.5	2.8	2.9	2.8
Amortization of prior service	0.9	0.9	0.9	0.6	0.6	0.5
Recognized actuarial loss	(4.3)	(3.1)	(6.0)	0.0	0.0	0.9
Net periodic benefit cost	$ (7.8)	$ (2.0)	$ (1.0)	$ 10.5	$ 10.2	$ 10.6

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits on a defined dollar basis. In 1998, the health care benefit consists of a contribution of up to $210 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. Effective January 1999, the Company amended the health care plan increasing the contribution to up $220 per retiree per month.

In addition to the above plans, employees are eligible to contribute to a 401(k) plan. The Company matches a portion of these contributions. Contributions charged to income for this plan for 1998, 1997, and 1996 were $2.5 million, $2.3 million, and $2.3 million, respectively.

Note 4

Operating Segment Financial Information

Under SFAS-131, information pertaining to operating segments is required to be reported. The prior years' segment results were not restated as the Company previously reported Electric and Gas segments and the unregulated segment was formed in 1998. Generally, operating segments are components of an enterprise that engage in business activities from which revenues may be earned and for which expenses are incurred, whose results are reviewed for purposes of resource allocation and performance evaluation, and for which discrete financial information is available. Upon adoption of SFAS-131, the Company identified three operating segments, driven by the types of products and services offered and regulatory environment under which the Company primarily operates. The three segments are Regulated Electric, Regulated Gas, and Unregulated. The Regulated segments' financial records are maintained in accordance with generally accepted accounting principles (GAAP) and Public Service Commission (PSC) accounting policies. The Unregulated segment's financial records are maintained in accordance with GAAP.

During the reported periods, all revenues are from United States sources except for $1.2 million from Canada, and all assets are located in the United States. No single customer represents more than 10% of the overall Company revenue.

The Regulated Electric segment supplies electric distribution services wholly within New York State. It produces electricity, and distributes and sells electricity to retail customers within a franchise area centering about the City of Rochester. It also sells electricity on a wholesale basis to other electric utilities throughout the Northeast and to energy marketers who resell that electricity to retail customers.

The Regulated Gas segment supplies gas services wholly within New York State. Gas is purchased and distributed to retail customers and distributed on behalf of other large or aggregated customers who purchase their own gas supply.

The Unregulated segment includes Energetix and RGS Development Corporation, both unregulated subsidiaries of the Company formed in 1998. In August, 1998, Energetix acquired Griffith Oil Inc., the second largest propane and oil distribution company in New York State. Energetix brings energy products and services to the marketplace both within and outside of the Company's regulated franchise area. These energy products and services include appliance warranty and repair, electricity, gasoline, natural gas, oil, and propane. RGS Development Corporation was formed to pursue unregulated business opportunities in the energy marketplace.

(Thousands of Dollars)	1998	1997	1996
REGULATED ELECTRIC			
Profit	$ 93,762	$ 82,765	$ 83,528
Revenues from External Customers	$ 687,100	$ 700,329	$ 707,768
Revenues from Intersegment Transactions	$ 8,984	—	—
Interest Revenue	$ 1,694	$ 3,379	$ 1,455
Depreciation and Amortization	$ 102,123	$ 103,395	$ 92,615
Regulatory Amortization	$ 15,080	$ 23,409	$ 23,743
Nuclear Fuel Amortization	$ 18,138	$ 17,419	$ 16,209
Interest Expense	$ 36,122	$ 40,583	$ 45,218
Income Tax Expense	$ 62,900	$ 58,682	$ 58,950
Capital Expenditures, Net	$ 96,206	$ 58,522	$ 95,334
Total Identifiable Assets	$1,941,622	$1,783,825	$1,877,224

(Note 4 continued on page 36)

(continued from page 35)

(Thousands of Dollars)	1998	1997	1996
REGULATED GAS			
Profit	$ 3,610	$ 12,595	$ 13,983
Revenues from External Customers	$ 274,540	$ 336,309	$ 346,279
Revenues from Intersegment Transactions	$ 72	—	—
Interest Revenue	$ 424	$ 845	$ 364
Depreciation and Amortization	$ 12,867	$ 13,127	$ 12,999
Regulatory Amortization	$ 1,461	$ 1,337	$ 1,677
Interest Expense	$ 9,030	$ 10,145	$ 11,305
Income Tax Expense	$ 504	$ 2,893	$ 7,101
Capital Expenditures, Net	$ 28,075	$ 25,546	$ 18,940
Total Identifiable Assets	$ 433,029	$ 441,849	$ 447,865

(Thousands of Dollars)	1998	1997	1996
UNREGULATED			
(Loss)	$ (3,234)	$ —	$ —
Revenues from External Customers	$ 81,778	$ —	$ —
Interest Revenue	$ 158	$ —	$ —
Depreciation and Amortization	$ 854	$ —	$ —
Goodwill Amortization	$ 278	$ —	$ —
Interest Expense	$ 943	$ —	$ —
Income Tax Benefit	$ (1,503)	$ —	$ —
Capital Expenditures, Net	$ 5,005	$ —	$ —
Total Assets	$ 59,946	$ —	$ —

There are intersegment transactions which occur between the Regulated segments and the Unregulated segment. These transactions are governed by guidelines established in the Competitive Opportunities Settlement and other PSC proceedings. The Unregulated segment is charged for the provision of services and for an allocation of other corporate costs by the Regulated Segments on a fully loaded cost basis. The Unregulated segment buys electricity from the Regulated Electric segment at rates established through PSC proceedings. The Unregulated segment also pays the Regulated segments for electric and gas distribution services at rates established through PSC proceedings. The total amount of the revenues identified by operating segment do not equal the total Company consolidated amounts as shown in the Consolidated Statement of Income. This is due to the elimination of certain intersegment revenues during consolidation. The total assets identified by operating segment do not equal the total Company consolidated amounts as shown in the Consolidated Balance Sheet. This is due to the elimination of certain intersegment transactions during consolidation, and certain common assets being unidentifiable by segment. A reconciliation follows:

(Thousands of Dollars)	1998	1997	1996
Revenues			
Regulated Electric	$687,100	$700,329	$707,768
Regulated Gas	274,540	336,309	346,279
Unregulated	81,778	—	—
Total	1,043,418	1,036,638	1,054,047
Reported on Consolidated Income Statement	1,034,362	1,036,638	1,054,047
Difference to Reconcile	$ 9,056	$ —	$ —
Intersegment Revenues			
Regulated Electric from Unregulated	$ 8,984	$ —	$ —
Regulated Gas from Unregulated	72	—	—
Total Intersegment	$ 9,056	$ —	$ —

(Thousands of Dollars)	1998	1997	1996
Assets			
Regulated Electric	$1,941,622	$1,783,825	$1,877,224
Regulated Gas	433,029	441,849	447,865
Unregulated	59,946	—	—
Cash and Cash Equivalents, Regulated Operations	5,375	25,405	21,301
Unamortized Debt Expense	17,241	16,944	14,820
Investment in Subsidiaries	11,202	—	—
Other	266	266	266
Intersegment Eliminations	(15,746)	—	—
Total Assets	$2,452,935	$2,268,289	$2,361,476

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 capability (summer)	788	1,128
RG&E's share—megawatts	189	158
—percent	24	14
Year of completion	1980	1988
	Millions of Dollars at December 31, 1998	
Plant In Service Balance	$99.6	$881.8
Accumulated Provision For Depreciation	$43.6	$490.9
Plant Under Construction	$ 0.0	$ 0.7

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

%	Series	Due	(Thousands of Dollars) Principal Amount December 31 1998	1997
6.7	X	July 1, 1998	$ —	$ 30,000
8⅜	OO (a)	Dec. 1, 2028	—	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
5.84	(b) (d)	Dec. 22, 2008	50,000	—
			$ 510,500	$ 516,000
Net bond discount			(498)	(566)
Less: Due within one year			—	30,000
Total			$ 510,002	$ 485,434

(a) The 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 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 (NYSERDA) through a participation agreement with the Company. Payments of the principal of, and interest on the Series 1992 A and Series 1992 B Bonds are guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation.
(b) The Series QQ First Mortgage Bonds and the 7%, 7.15%, 7.13%, 6.375% and 5.84% 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.
(d) In 1998 the Company issued $50 million under a medium-term note program entitled "First Mortgage Bonds, Designated Secured Medium-Term Notes, Series B" 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 1997 and 1996 requirements were met with funds deposited with the Trustee, and these funds were used for redemption of outstanding bonds of Series Y.

On December 1, 1998 the Company redeemed all its outstanding First Mortgage 8⅜% Bonds, due December 1, 2028, Series OO.

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

	(Thousands of Dollars) 1999	2000	2001	2002	2003
7% Series		$30,000			
Series QQ				$100,000	
7.15% Series					$39,000
7.13% Series					1,000
6.375% Series					40,000
	$ —	$30,000	$ —	$100,000	$80,000

PROMISSORY NOTES AND OTHER

Issued	Due	(Thousands of Dollars) December 31 1998	1997
September 2, 1998 (e)	September 1, 2033	$ 25,500	$ —
August 19, 1997 (f)	August 1, 2032	101,900	101,900
August 3, 1998 (g)	August 3, 2005	24,563	—
December 1, 1998 (h)	March 31, 2014	94,761	—
Other Long Term Debt of Subsidiaries (i)		1,500	—
Total		$248,224	$101,900

(e) The $25.5 million Promissory Note was issued in connection with NYSERDA's 5.95% Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), 1998 Series A. Payment of the principal of, and interest on the Series A Bonds is guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation.

(f) Multi-mode pollution control notes totaling the principal amount of $101.9 million were issued in connection with NYSERDA's Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), $34,000,000 1997 Series A, $34,000,000 1997 Series B and $33,900,000 1997 Series C. The Multi-mode Revenue Bonds have a structure that enables the Company to optimize the use of short-term rates by allowing for the interest rates to be based on a daily rate, a weekly rate, a commercial paper rate, an auction rate or a multi-year fixed rate. Payment of the principal of, and interest on the Multi-mode Revenue Bonds is guaranteed under Bond Insurance Policies by MBIA Insurance Corporation. At December 31, 1998 and December 31, 1997, the Multi-mode Revenue Bonds bore interest at the weekly rate and the average annual interest rate for all three series was 3.21% and 3.65%, respectively.

The Company is obligated to make payments of principal, premium and interest on each Promissory Note which corresponds to the payments of principal, premium, if any, and interest on certain Pollution Control Revenue Bonds issued by NYSERDA as described above.

(g) The $24.6 million Promissory Note was issued in connection with the acquisition of Griffith Oil, Inc. by Energetix and is secured by a pledge of the stock of Griffith Oil, Inc. The Company has made a financial guarantee on behalf of Energetix which obligates the Company in the event of a default by Energetix in payments under the Note. Payments of principal are made in seven annual installments and interest for the first three years accrues at the rate of 7% per year and thereafter at rates varying between 7%-8½% per year.

(h) The Promissory Note was issued in connection with the Kamine Global Settlement Agreement (See Note 10.) The Promissory Note is secured by a mortgage, the lien for which is subordinate to the lien of the First Mortgage. The $94.8 million liability represents the present value at December 31, 1998 of future obligations under the Note assuming a discount rate of 7.5 percent. This balance will decrease as payments are made over the term of the Note. During 1998 the Company made payments totaling $7.8 million. In 1999 the Company expects to make payments totaling $9.6 million and thereafter, payments totaling $10.6 million per year.

(i) Represents mainly promissory notes under various distribution seller agreements of Energetix aggregating $1,927 less $427 due within one year.

Based on an estimated borrowing rate at year-end 1998 of 5.84% for long-term debt with similar terms and average maturities (12 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $844 million at December 31, 1998.

Based on an estimated borrowing rate at year-end 1997 of 6.62% 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 $655 million at December 31, 1997.

NOTE 7

Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	820,000*
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, 1998	(Thousands) December 31 1998	1997	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
Total		470,000	$47,000	$47,000	

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, 1998	(Thousands) December 31 1998	1997	Optional Redemption (per share)
7.55	T	—	$ —	$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		350,000	$35,000	$45,000	
Less: Due within one year		100,000	10,000	10,000	
Total		250,000	$25,000	$35,000	

+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 U. All of the shares are subject to redemption pursuant to mandatory sinking funds on September 1, 1999 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 1998 of 4.75% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (6.61 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $39 million at December 31, 1998.

Based on an estimated dividend rate at year-end 1997 of 5.67% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (5.92 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $48 million at December 31, 1997.

NOTE 8

Common Stock and Stock Options

REPURCHASE PLAN

In December 1997, the Board of Directors of the Company authorized the repurchase of up to 4.5 million shares of the Company's Common Stock on the open market. A total of 1,507,000 of the shares were purchased in 1998.

	Shares Outstanding	Amount (Thousands)
Balance, December 31, 1997	0	$ 0
Reacquired through Repurchase Plan	(1,507,000)	(46,433)
Balance, December 31, 1998	(1,507,000)	$ (46,433)

COMMON STOCK

At December 31, 1998, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 37,378,813 were outstanding. No shares of Common Stock are reserved for warrants, conversions, or other rights. There were 1,965,651 shares of Common Stock reserved for employees under the 1996 Performance Stock Option Plan, as further described below. There were 1,026,840 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 129,664 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

	Shares Outstanding	Amount (Thousands)
Balance, December 31, 1995	38,453,163	$687,518
Shares Issued through Stock Plans	398,301	8,612
Decrease (Increase) in Capital Stock Expense	—	(111)
Balance, December 31, 1996	38,851,464	$696,019
Shares Issued through Stock Plans	10,883	272
Additional Paid in Capital	—	2,399
Decrease (Increase) in Capital Stock Expense	—	341
Balance, December 31, 1997	38,862,347	$699,031
Shares Issued through Stock Plans	23,466	586
Additional Paid in Capital	—	99
Repurchase Plan	(1,507,000)	(46,433)
Decrease (Increase) in Capital Stock Expense	—	14
Balance, December 31, 1998	37,378,813	$653,297

PERFORMANCE STOCK OPTION PLAN

The Company has a Performance Stock Option Plan which provides for the granting of options to purchase up to 2,000,000 authorized but unissued shares or treasury shares of $5 par value Common Stock to executive officers and other key employees. No participant shall be granted options for more than 200,000 shares of Common Stock during any calendar year. The options would be exercisable for a period to be determined by the Committee on Management of the Board of Directors (the Committee). The Committee grants the right to receive a cash payment upon any exercise of an option equal to the quarterly dividend payment per share of Common Stock paid from the date the option was granted to the date of exercise.

In 1998, the Board of Directors granted 27,984 options at an exercise price of $33.9065 per share and 15,157 options at an exercise price of $31.0005 per share. These options are vested at 25% when the stock closes at $35 per share, 50% at $40 per share, 75% at $45 per share and 100% at $50 per share. These options are exercisable for a period of 10 years. The weighted average grant date option fair value is $5.56. The weighted average contractual remaining life at December 31, 1998 is 9.10 years.

(Note 8 continued on page 42)

(continued from page 41)

In 1997, the Board of Directors granted 504,700 options at an exercise price of $19.0625 per share. These options are vested at 50% when the stock closes at $25 per share, 75% at $30 per share and 100% at $35 per share. Also in 1997, the Board of Directors granted 50,159 options at an exercise price of $24.75 per share. These options are vested at 25% when the stock closes at $25 per share, 50% at $30 per share, 75% at $35 per share and 100% at $40 per share. These options are exercisable for a period of 10 years. The weighted average grant date option fair value is $4.60. The weighted average contractual remaining life at December 31, 1998 is 8.13 years.

In order for the options to become vested, the closing prices must be sustained at or above the levels indicated above for a minimum of five consecutive trading days.

Since the Company adopted SFAS-123, compensation expense associated with the options granted is reflected in 1997 and 1998 net income. The compensation expense recorded was $2,399,000 in 1997 and $239,800 in 1998. The compensation expense was calculated using the shorter of the anticipated or actual vesting period. In applying SFAS-123, the fair value of each option granted is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions: risk-free rate of return ranging between 6.39% and 6.56% for 1997 and 5.54% to 5.65% for 1998, expected dividend yield of 0% for 1997 and 1998, and expected stock volatility of 17% for 1997 and 1998.

A summary of the Company's stock option activity is presented below:

	Options	Weighted Average Exercise Price
Options granted 1997	554,859	$19.577
Options exercised	(10,883)	$19.063
Outstanding at 12/31/97	543,976	$19.587
Vested at 12/31/97	392,722	$19.426
Available for future grant at 12/31/97	1,445,141	
Options granted 1998	43,141	$32.886
Options exercised	(23,466)	$19.063
Outstanding at 12/31/98	563,651	$20.627
Vested at 12/31/98	369,255	$19.449
Available for future grant at 12/31/98	1,402,000	

NOTE 9

Short-Term Debt

On December 31, 1998, the Company and its subsidiary, Energetix had short-term debt outstanding of $50.5 million and $6.5 million, respectively. At December 31, 1997 the Company had short-term debt outstanding of $20.0 million. At no time during 1997 did Energetix have any short-term debt outstanding. The weighted average interest rates on short-term debt outstanding at year-end 1998 for the Company and Energetix were 5.81% and 6.66%, respectively. The weighted average interest rates for borrowings during the year were 5.51% and 6.31%, respectively. The weighted average interest rate on short-term debt borrowed during 1997 for the Company was 6.07%.

The Company's $90 million revolving credit agreement currently terminates on December 31, 2001. Commitment fees related to this facility amounted to $97,705 in 1998 and $113,000 in 1997 and 1996. At the time of acquisition of Griffith Oil Co., Inc. by Energetix, Griffith secured a $15 million revolving credit agreement. Borrowings under this agreement are secured by personal property of Griffith.

Energetix has made a financial guarantee on behalf of Griffith which obligates Energetix in the event of a Griffith default.

The Company's Charter provides that the Company may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of the Company's total secured indebtedness, capital, and surplus without the approval of at least a majority of the holders of outstanding Preferred Stock. As of December 31, 1998, the Company would be able to incur approximately $93.8 million of additional unsecured debt under this provision. The Company has unsecured lines of credit totaling $47 million available from several banks, at their discretion.

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 $30 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.

NOTE 10

Commitments and Other Matters

Regulatory Assets

With PSC approval 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 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 (pursuant to SFAS-121). In certain cases, the entire amount could be written off.

SFAS-121 requires write-down of assets whenever events or circumstances occur which indicate that the carrying amount of a long-lived asset may not be fully recoverable.

Below is a summarization of the Regulatory Assets as of December 31, 1998 and 1997:

	(Millions of Dollars)	
	1998	1997
Income Taxes	$147.6	$159.6
Kamine	192.8	—
Uranium Enrichment Decommissioning Deferral	15.1	16.4
Deferred Ice Storm Charges	8.9	11.5
Deferred Environmental SIR Costs	20.9	12.4
Labor Day 1998 Storm Costs	7.2	—
Gas Deferred Fuel	10.7	7.1
Other, net	13.1	25.0
Total - Regulatory Assets	$416.3	$232.0

- 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, which varies from one to thirty years, when the effect of the past deductions reverses in future years.
- Kamine: This amount results from a settlement resolving all litigation, releasing all claims and terminating all electricity purchase obligations under a power purchase agreement.
- Uranium Enrichment Decommissioning Deferral: The Energy Policy Act of 1992 requires utilities to contribute such amounts based on the amount of uranium enriched by the United States Department

(Note 10 continued on page 44)

(continued from page 43)

of Energy (DOE) for each utility. This amount is mandated to be paid to DOE through the year 2007. The recovery of these costs is through base rates of fuel.

- 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.
- Deferred Environmental Site Investigation/Remediation Costs: These costs represent the Company's share of the estimated costs to investigate and perform certain remediation activities at both Company-owned and non-owned sites with which it may be associated. The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers, subject to the terms of the Competitive Opportunities Settlement.
- Labor Day 1998 Storm Costs: These costs result from a 1998 Labor Day storm. Under the Competitive Opportunities Settlement, the Company is entitled to defer, for later recovery in rates, certain costs, including those caused by "catastrophic events", when any single event results in costs exceeding $2.5 million. The Company has filed a petition with the PSC notifying them of the deferral of these storm costs..
- Gas Deferred Fuel: These costs result from a PSC-approved annual reconciliation of recoverable gas costs with gas revenues in which the excess or deficiency is refunded to or recovered from customers during a subsequent period.

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 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, 1998 depends on market prices and the competitive market in New York State which is still under development and subject to continuing changes which are not yet determinable, but could be significant. Strandable assets, if any, could be written down for impairment of recovery in the same manner as deferred costs discussed above.

In a competitive natural gas market, strandable assets would arise where customers migrate away from dependence on the Company for full service, leaving the Company with surplus pipeline and storage capacity, as well as natural gas supplies, under contract. The Company has been restructuring its transportation, storage and supply portfolio to reduce its potential exposure to strandable assets. Regulatory developments discussed under "Gas Cost Recovery" below, may affect this exposure; but whether and to what extent there may be an impact on the level and recoverability of strandable assets cannot be determined at this time.

At December 31, 1998 the Company believes that its regulatory and strandable assets, if any, are not impaired and are probable of recovery. The settlement approved in the Competitive Opportunities proceeding (Competitive Opportunities Settlement) does not impair the opportunity of the Company to recover its investment in these assets. However, the PSC issued an Opinion and Order Instituting Further Inquiry on March 20, 1998 to address issues surrounding nuclear generation. The ultimate determination in this proceeding could have an impact on strandable assets and the recovery of nuclear costs. The initial meeting in this Inquiry was held in January 1999 and such a determination is unlikely before year-end.

CAPITAL EXPENDITURES

The Company's 1999 construction expenditures program is currently estimated at $114 million. 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 amounts in its electric rates 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 $138.3 million through December 31, 1998 and is authorized to collect approximately $22 million annually through June 30, 2002 for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $296.3 million for Ginna and $112.8 million for the Company's 14% share of Nine Mile Two (1995 dollars). These estimates are based on site specific cost studies for each plant completed in 1995. 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 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 $107.3 million to this fund and, including realized and unrealized investment returns, the fund has a balance of $183.5 million as of December 31, 1998. 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, 1998 is $31.0 million.

The NRC has issued a policy statement relating to industry restructuring which addresses, in part, the prospects of joint and several liability of co-owners for nuclear decommissioning costs, such as co-owners of Nine Mile Two. The NRC recognizes that co-owners generally divide costs and output from their facilities by using a contractually-defined, pro rata share standard. The NRC has implicitly accepted this practice in the past and believes that it should continue to be the operative practice, but reserves the right, in highly unusual situations where adequate protection of public health and safety would be compromised if such action were not taken, to consider imposing joint and several liability on co-owners when one or more co-owners have defaulted.

The PSC in August 1997 issued for comment a report by its staff proposing norms by which nuclear plants in the state would relate to the competitive electricity market following the period covered by electric utility restructuring agreements then pending before the PSC. Among other things, the report envisioned the sale of these plants at auction, but with the selling utilities remaining responsible for ultimate decommissioning as well as for disposal of certain spent fuel. Recognizing that bidders may not be attracted to certain units — which could include both the Company's Ginna plant and the Nine Mile Two plant in which it has a 14% interest, the report contemplated their early shutdown unless they could compete with other forms of generation. In Fall 1997, the Company and others commented on these and other facets of the report. On March 20, 1998 the PSC issued an Opinion and Order Instituting Further Inquiry. In December 1998 the PSC issued a Notice of Collaborative Conference to further examine the future treatment of nuclear generation. The initial collaborative conference in this proceeding will be held in January, 1999.

The Staff of the Financial Accounting Standards Board is studying the recognition, measurement and classification of certain liabilities related to the closure or removal of long lived assets. This could affect the accounting for the decommissioning costs of the Company's nuclear generating stations. 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 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.

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. On June 12, 1998, 16 electric utilities from across the country, including the Company, filed a multi-count complaint against the United States government in the United States District Court for the Southern District of New York. The suit challenges the constitutionality of a $2.25 billion retroactive assessment imposed by

Note 10 continued on page 46

(continued from page 45)

the federal government on domestic nuclear power companies to pay for the clean up of the federal government's three uranium enrichment plants. Those plants are located at Oak Ridge, Tennessee, Paducah, Kentucky, and Portsmouth, Ohio. The Oak Ridge plant went into operation in 1945, and the other two plants began operation during the 1950s.

The assessment, enacted by Congress as part of the Energy Policy Act of 1992, is based on the amount of uranium enrichment services purchased by the utilities as far back as the 1950s and is to be collected over a 15-year period. The assessment, if not overturned, would relieve the government of a substantial portion of the costs it would otherwise have to pay for decommissioning and decontaminating its three uranium enrichment facilities. In their complaint, the utilities seek a declaratory judgment that the assessment violates the due process clause of the Constitution because it abrogates vested rights the utilities obtained under fixed-price agreements with the government when they purchased uranium enrichment services. The utilities also challenge the assessment as unreasonably retroactive. The suit seeks an injunction prohibiting the government from continuing to collect the assessment from the plaintiff utilities.

The assessments for Ginna and the Company's share of Nine Mile Two are estimated to total $22.1 million, excluding inflation and interest. Installments aggregating approximately $11.2 million have been paid through 1998. 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, 1998 is $13.9 million ($12.2 million as a long-term liability and $1.7 million as a current liability). The Company is recovering costs through base rates of fuel.

Nuclear Fuel Disposal Costs. The Nuclear Waste Policy Act (Nuclear Waste Act) of 1982, as amended, requires the 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. In December 1996 the DOE notified the Company that the DOE will not start acceptance of Ginna spent fuel in 1998. 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 $87.6 million at December 31, 1998. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Nuclear Waste Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of approximately one mill ($.001) per KWH of nuclear energy generated and sold. This charge (approximately $4.7 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. In November 1998 the Company completed installation of seven high-capacity spent fuel racks in the spent fuel pool. This will allow interim storage capacity of all spent fuel discharged from the Ginna Plant through the end of its Operating License in the year 2009.

Environmental Matters

The Company is subject to federal, state and local laws and regulations dealing with air and water quality and other environmental matters. Environmental matters may expose the Company to potential liabilities which, in certain instances, may be imposed without regard to fault or historical activities which were lawful at the time they occurred. The Company continually monitors its activities in order to determine the impact of its activities on the environment and to ensure compliance with various environmental laws. The Company has recorded a total liability of approximately $24.2 million in connection with Site Investigation and/or Remediation (SIR) efforts where disposal of certain waste products may

have occurred. Estimates of the SIR costs for each of these sites range from preliminary to highly refined. The Company expects to pay these SIR costs over the next ten years. These estimates could change materially, based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations. Liability may be joint and several for certain of these sites. There may be additional costs with respect to these and possibly other sites, the materiality of which is not presently determinable.

Company-Owned Electric and Gas Waste Site Activities. The Company is conducting proactive SIR efforts at seven Company-owned sites where past waste handling and disposal may have occurred. Remediation activities at five of these sites are in various stages of planning or completion and the Company is conducting a program to restore the other two sites. The Company has recorded a liability of approximately $21.6 million for SIR efforts at the seven Company-owned sites in the Rochester, NY area.

Superfund and Non-Owned Other Sites. The Company has been or may be associated as a potentially responsible party at eight sites not owned by it and has recorded estimated liabilities of approximately $.8 million in connection with SIR efforts at these sites. The Company has signed orders on consent for five of these sites.

Griffith Facilities. The Company's subsidiary, Energetix, recently acquired Griffith Oil, Inc. A review and audit was conducted of all Griffith facilities by a nationally recognized engineering firm as part of the due diligence acquisition process by Energetix. As a result of the review of 43 sites and subsequent subsurface investigations of 26 sites, thirteen new New York State Department of Environmental Conservation (NYSDEC) spill numbers were assigned. These sites are currently undergoing evaluation and remediation planning for corrective action. Using historical NYSDEC remedial actions as a guide, Energetix estimates the accrual of aggregate cleanup costs over a five-year period for all 43 sites approximates $1.8 million.

Gas Cost Recovery

The Company entered into several agreements to help manage its pipeline capacity costs and has successfully met Settlement targets for capacity remarketing for the twelve months ending October 31, 1998, thereby avoiding negative financial impacts for that period. In July, the Company entered into an agreement with Dynegy Marketing and Trade to provide assistance with respect to the management of the Company's gas supply, transportation and storage costs consistent with the goal of providing reliable service and reducing the cost of gas.

On October 16, 1998, the Company, the staff of the PSC and certain other parties entered into an interim settlement agreement, designed to address the period between expiration of the 1995 Settlement and the implementation of a new multi-year settlement to be negotiated. The interim settlement was approved by the PSC on November 4, 1998. In its ruling, the PSC indicated that the allocation of transition costs that result from the migration of customers to other gas suppliers under the Interim Settlement Agreement may be subject to revision after it considers similar issues in another case. Major elements of the interim settlement include: (1) the term is from December 1, 1998 through the earlier of June 30, 1999 or the effective date of a new multi-year agreement; (2) base rates, which cover the cost of the local distribution system, will remain frozen for all customers at their current level (which were fixed at the July 1994 level pursuant to the 1995 Settlement that expired on October 31, 1998), while the Gas Cost Adjustment will continue to vary from month to month; (3) a level of revenues ($11.9 million on an annual basis) which corresponds to the Company's anticipated revenues from capacity remarketing transactions currently in place is imputed to the Company; (4) the Company will share 15% of the savings realized from the reduction of capacity commitments; (5) the Company will simplify the transportation gas program and cap the migration of customers at 10% of annual retail sales and not assign capacity costs to certain migrating customers; (6) the Company will be allowed to recover the upstream costs that may be stranded by migration; and, (7) certain issues relating to past gas costs have been resolved whereby the Company shall set aside, in a manner to be determined by the PSC for the benefit of customers, $2.2 million of the total amount recovered through the Gas Cost Adjustment.

(Note 10 continued on page 48)

continued from page 47

LITIGATION

Spent Nuclear Fuel Litigation. The federal Nuclear Waste Act obligated DOE to accept for disposal spent nuclear fuel (SNF) from utilities' powerplants by January 31, 1998 (Statutory deadline). Since the mid-1980s, the Company and other nuclear plant owners and operators have paid substantial fees to DOE to fund that obligation (Nuclear Waste Fund). That DOE would not meet its obligation was evident well prior to 1998; DOE admitted as much as the statutory deadline approached.

In 1994, Northern States Power Company and other owners of nuclear plants filed suit against DOE and the federal government in the U.S. Court of Appeals for the District of Columbia Circuit (Court) seeking a declaration that DOE's course of action was in violation of its statutory obligation and requesting other relief. In 1996, the Court upheld the utilities' position that DOE is obligated to accept and dispose of the utilities' SNF by the statutory deadline. The Court rejected the DOE contention that it could defer the disposal until the availability of a suitable SNF repository, but stopped short of providing the utilities a remedy since DOE had not yet defaulted.

In late 1996, DOE invited nuclear utilities' views on how its anticipated inability to meet the statutory deadline could "best be accommodated." The Company and a number of other parties responded to that invitation.

By a Joint Petition for Review, the Company and other nuclear utilities petitioned the Court in January 1997 for a declaration that the Petitioners were relieved of the obligation to pay fees into the Nuclear Waste Fund, and were authorized to place those fees into escrow until DOE commences disposing of SNF. The petition further requested that DOE be ordered to develop a program that would enable it to begin acceptance of SNF by the statutory deadline. In November 1997, the Court held that DOE could not delay acceptance on grounds that it lacked an SNF repository, and that the utilities had a "clear right to relief". Rather than grant funding relief and order the DOE to move SNF, however, the Court referred the utilities to their contractual remedies against DOE. State agencies, municipal governments and DOE sought review of this decision, but the U.S. Supreme Court declined in November 1998 to hear the case. The Company, joined by several other nuclear utilities, in July 1998 initiated a further effort to have the Court provide a suitable remedy under its "original and exclusive" jurisdiction over matters arising under the Nuclear Waste Act. The Court has yet to rule on that request.

DOE's failure to meet its statutory deadline has given rise to numerous other lawsuits. For example, several plant operators brought suit against DOE in the U.S. Court of Federal Claims. In decisions issued in October and November 1998, that court held that DOE had breached its contractual obligations. It denied most portions of DOE motions to dismiss the operators' claims and granted the operators' summary judgment on DOE contract liability.

It is not possible to predict the future course of this obligation or the resolution of the spent nuclear fuel movement and storage concern that underlies it. The current court rulings on the DOE's default in meeting its obligation to remove SNF by the statutory deadline, and on its contractual liability therefor, have been promising. The current court rulings appear to have prompted greater DOE effort to complete site investigations at its Yucca Mountain, NV, site for SNF disposal and to focus greater Congressional attention on the inappropriateness of continuing to house SNF around the nation at short-term SNF facilities of nuclear powerplants. These developments have not yet led, however, either to a firm schedule for DOE's movement of SNF from plant facilities to a permanent repository or to the authorization of plant owners and operators to withhold their Nuclear Waste Fund payments to DOE until that schedule is established. The Company and other nuclear utilities continue to work toward those objectives.

Litigation With Co-Generator. On December 1, 1998 the Company completed the closing under its Global Settlement Agreement with General Electric Capital Corporation (GECC), Kamine/Besicorp Allegany L.P. (Kamine) and other Kamine affiliates. In connection with the closing, the Company paid $10 million and gave a promissory note in the aggregate amount of $168 million payable to GECC. The promissory note is secured by a general mortgage on the Company's property which mortgage is subject and subordinate to the Company's First Mortgage. The mortgage is not recorded but may be recorded in the event of default. In addition, the Company purchased the gas-fired generation facility rated at 65Mw for $15 million. The Global Settlement was approved by the PSC which authorized the Company to recover the payments in rates.

Other Matters

Other Statement of Income Items. The change in Other Income and Deductions, Other-net in 1998 reflects the recognition of income due to the reversal of certain deferred credits in accordance with the Competitive Opportunities Settlement. In prior years, the PSC had required the Company to establish deferred credits to account for certain pension and other post-employment benefit charges and Nine Mile Two operating and maintenance expenses. In 1998, these deferred credits totaling $17.4 million were eliminated consistent with the terms of the Settlement and discussions with the PSC. An amount of $8.8 million associated with certain pension charges was reflected on the Company's books in the first quarter of 1998, after the Company received the written order associated with the Competitive Opportunities Settlement. An amount of $6.0 million associated with certain Nine Mile Two operating and maintenance expenses was reflected ratably over each of the four quarters of 1998, consistent with Nine Mile Two accounting practices. The remainder associated with certain other post-employment benefits was reflected in the second quarter of 1998, after the Company had concluded discussions with the PSC. The Company does not have any deferred credits which are subject to PSC Orders which would permit the recognition of any significant credits to income in the future. This income was partially offset by expenses associated with the gas interim settlement agreement.

EITF Issue 97-4—Deregulation of the Pricing of Electricity. In July 1997, the Financial Accounting Standards Board's Emerging Issues Task Force (EITF) reached a consensus on accounting rules for utilities' transition plans for moving to more competitive environments and provided guidance on when utilities with transition plans will need to discontinue the application of SFAS-71, "Accounting for the Effects of Certain Types of Regulation".

The major EITF consensus was that the application of SFAS-71 to a segment (e.g. generation) which is subject to a deregulation transition plan should cease when the legislation or enabling rate order contains sufficient detail for the utility to reasonably determine what the transition plan will entail. The EITF also concluded that a decision to continue to carry some or all of the regulatory assets (including stranded costs) and liabilities of the separable portion of the business that is discontinuing the application of SFAS-71 should be determined on the basis of where the regulated cash flows to realize and settle them will be derived. If a transition plan provides for a non-bypassable fee for the recovery of stranded costs, there may not be any significant write-off if SFAS-71 is discontinued for a segment.

The Company's application of the EITF 97-4 consensus has not affected its financial position or results of operations because any above-market generation costs, regulatory assets and regulatory liabilities associated with the generation portion of its business will be recovered by the regulated portion of the Company through its distribution rates, given the Settlement provisions. The Settlement provides for recovery of all prudently incurred sunk costs (all investment in electric plant and electric regulatory assets) as of March 1, 1997 by inclusion in rates charged pursuant to the Company's distribution access tariff. The Settlement also states that "the Parties intend that the provisions of this Settlement will allow the Company to continue to recover such costs, during the term of the Settlement, under SFAS-71", and that "such treatment shall be consistent with the principle that the Company shall have a reasonable opportunity beyond July 1, 2002 to recover all such costs". The fixed portion of the non-nuclear generation to-go costs after July 1, 1999 and the variable portion of the non-nuclear generation to-go costs after July 1, 1998 are subject to market forces and would no longer be able to apply SFAS-71. The Company's net investment at December 31, 1998 in nuclear generating assets is $666.9 million and in non-nuclear generating assets is $117.9 million.

Lease Agreements. The Company, including Energetix, leases 15 properties for administrative offices, operating activities and vehicles. The total lease expense charged to operations was $4.8 million, $4.2 million and $3.9 million in 1998, 1997 and 1996, respectively. For the years 1999, 2000, 2001, 2002 and 2003 the estimated lease expense charged to operations will be $5.2 million, $3.4 million, $3.3 million, $2.9 million and $2.8 million, respectively. Commitments under capital leases were not significant to the accompanying financial statements.

Gas Purchase Commitments. Energetix has entered into natural gas purchase commitments with numerous gas suppliers. These commitments support a fixed price offering to retail gas customers.

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 PricewaterhouseCoopers 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 PricewaterhouseCoopers LLP is presented on page 24.

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, 1998, the Company maintained an effective system of internal control over the preparation of its published financial statements.

Thomas S. Richards
Chairman of the Board, President and
Chief Executive Officer

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

January 20, 1999

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. The sum of the quarterly earnings per share may not equal the fiscal year earnings per share due to rounding.

	(Thousands of Dollars)				Earnings per Common Share (in dollars)	
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Basic	Diluted
December 31, 1998	$ 287,106	$ 22,345	$ 15,015	$ 14,088	$0.37	$0.37
September 30, 1998	253,606	34,444	25,213	23,908	0.62	0.62
June 30, 1998[1]	211,134	22,203	15,655	14,350	0.37	0.37
March 31, 1998[1]	282,516	48,168	38,255	36,950	0.95	0.95
December 31, 1997	$ 271,039	$ 24,406	$ 14,031	$ 12,726	$0.32	$0.32
September 30, 1997	221,335	34,616	21,724	20,419	0.52	0.52
June 30, 1997	229,419	31,125	18,172	16,681	0.42	0.42
March 31, 1997	314,845	55,194	41,433	39,729	1.02	1.02
December 31, 1996[1]	$ 274,431	$ 33,048	$ 22,228	$ 20,362	$0.52	$0.52
September 30, 1996	234,843	36,159	21,062	19,196	0.49	0.49
June 30, 1996	235,577	23,115	11,732	9,866	0.25	0.25
March 31, 1996	309,195	56,866	42,489	40,623	1.05	1.05

[1]Reclassified for comparative purposes.

Common Stock and Dividends

Earnings/Dividends	1998	1997	1996
Earnings per share			
—basic	$2.32	$2.30	$2.32
—diluted	$2.31	$2.30	$2.32
Dividends paid per share	$1.80	$1.80	$1.80

Shares/Shareholders	1998	1997	1996
Number of shares (000's)			
Weighted average			
—basic	38,462	38,853	38,762
—diluted	38,600	38,909	38,762
Actual number at December 31	37,379	38,862	38,851
Number of shareholders at December 31	28,995	31,337	33,675

TAX STATUS OF CASH DIVIDENDS.

Cash dividends paid in 1998, 1997 and 1996 were 100 percent taxable for federal income tax purposes.

DIVIDEND POLICY.

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

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1999, the Company paid a cash dividend of $.45 per share on its Common Stock. The January 1999 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."

	1998	1997	1996
Common Stock—Price Range			
High			
1st quarter	33 1/4	20 5/8	23 1/4
2nd quarter	32 1/4	21 7/16	21 7/8
3rd quarter	32 7/16	24 15/16	21 1/8
4th quarter	33 1/4	34 1/2	19 5/8
Low			
1st quarter	29 1/2	18 7/8	21 1/4
2nd quarter	29 9/16	18	19 7/8
3rd quarter	28 3/8	20 5/8	18
4th quarter	28 9/16	23 1/4	17 7/8
At December 31	31 1/4	34	19 5/8

SELECTED FINANCIAL DATA

(Thousands of Dollars) Year Ended December 31	1998	1997*	1996*	1995*	1994*	1993*
Consolidated Summary of Operations						
Operating Revenues						
Electric	$ 687,970	$ 700,329	$ 707,768	$ 722,465	$ 674,753	$655,316
Gas	275,177	336,309	346,279	293,863	326,061	293,708
Other	71,215	—	—	—	—	—
Total Operating Revenues	1,034,362	1,036,638	1,054,047	1,016,328	1,000,814	949,024
Operating Expenses						
Fuel Expenses						
Fuel for electric generation	53,954	47,665	40,938	44,190	44,961	45,871
Purchased electricity	27,024	28,347	46,484	54,167	37,002	31,563
Gas purchased for resale	155,497	196,579	202,297	167,762	194,390	166,884
Unregulated fuel expenses	60,001	—	—	—	—	—
Total Fuel Expenses	296,476	272,591	289,719	266,119	276,353	244,318
Operating Revenues Less Fuel Expenses	737,886	764,047	764,328	750,209	724,461	704,706
Other Operating Expenses						
Operations and maintenance excluding fuel expenses	301,625	315,109	313,157	308,433	296,741	302,035
Unregulated operating and maintenance expenses excluding fuel	13,257	—	—	—	—	—
Depreciation and amortization	116,122	116,522	105,614	91,593	87,461	84,177
Taxes—local, state and other	118,337	121,796	126,868	133,895	129,778	126,892
Federal income tax—current	70,541	69,812	65,757	65,368	35,658	33,453
—deferred	(9,156)	(4,533)	3,744	847	25,587	15,877
Total Other Operating Expenses	610,726	618,706	615,140	600,136	575,225	562,434
Operating Income	127,160	145,341	149,188	150,073	149,236	142,272
Other (Income) and Deductions						
Allowance for other funds used during construction	(408)	(351)	(684)	(585)	(396)	(153)
Federal income tax	516	(3,704)	(3,450)	(16,948)	(16,259)	(9,827)
Regulatory disallowances	—	—	—	26,866	600	1,953
Pension Plan Curtailment	—	—	—	—	33,679	8,179
Other, net	(13,181)	3,308	(712)	9,631	(923)	2,113
Total Other (Income) and Deductions	(13,073)	(747)	(4,846)	18,964	16,701	2,265
Interest Charges						
Long-term debt	42,590	44,615	48,618	53,026	53,606	56,451
Short-term debt	431	47	21	398	1,808	1,487
Other, net	3,727	6,629	9,307	8,658	4,758	5,220
Allowance for borrowed funds used during construction	(653)	(563)	(1,423)	(2,901)	(2,012)	(1,714)
Total Interest Charges	46,095	50,728	56,523	59,181	58,160	61,444
Net Income	94,138	95,360	97,511	71,928	74,375	78,563
Dividends on Preferred Stock at Required Rates	4,842	5,805	7,465	7,465	7,369	7,300
Earnings Applicable to Common Stock	$ 89,296	$ 89,555	$ 90,046	$ 64,463	$ 67,006	$ 71,263
Earnings per Common Share—Basic	$2.32	$2.30	$2.32	$1.69	$1.79	$2.00
Earnings per Common Share—Diluted	$2.31	$2.30	$2.32	$1.69	$1.79	$2.00
Cash Dividends Declared per Common Share	$1.80	$1.80	$1.80	$1.80	$1.77	$1.73

*Reclassified for comparative purposes.

Condensed Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1998	1997*	1996*	1995*	1994*	1993*
Assets						
Utility Plant	$3,326,995	$3,234,077	$3,159,759	$3,068,103	$2,981,151	$2,890,799
Less: Accumulated depreciation and amortization	1,863,475	1,714,368	1,569,078	1,518,878	1,423,098	1,335,083
	1,463,520	1,519,709	1,590,681	1,549,225	1,558,053	1,555,716
Construction work in progress	98,554	74,018	69,711	121,725	128,860	112,750
Net utility plant	1,562,074	1,593,727	1,660,392	1,670,950	1,686,913	1,668,466
Current Assets	202,963	242,371	250,461	292,596	236,519	248,589
Investment in Empire	—	—	—	38,879	38,560	38,560
Intangible Assets	21,062	—	—	—	—	—
Deferred Debits and Other Assets	666,836	432,191	450,623	453,726	484,962	488,527
Total Assets	$2,452,935	$2,268,289	$2,361,476	$2,456,151	$2,446,954	$2,444,142
Capitalization and Liabilities						
Capitalization						
Long-term debt	$ 758,226	$ 587,334	$ 646,954	$ 716,232	$ 735,178	$ 747,631
Preferred stock redeemable at option of Company	47,000	47,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	25,000	35,000	45,000	55,000	55,000	42,000
Common shareholders' equity:						
Common stock	699,730	699,031	696,019	687,518	670,569	652,172
Retained earnings	129,484	109,313	90,540	70,330	74,566	75,126
Less: Treasury stock at cost (1,507,000 shares)	46,433	—	—	—	—	—
Total common shareholders' equity	782,781	808,344	786,559	757,848	745,135	727,298
Total Capitalization	1,613,007	1,477,678	1,545,513	1,596,080	1,602,313	1,583,929
Long-Term Liabilities (Department of Energy and Site Remediation)	123,920	110,352	106,578	101,561	88,500	89,804
Current Liabilities	183,369	175,691	145,391	171,664	180,653	234,530
Deferred Credits and Other Liabilities	532,639	504,568	563,994	586,846	575,488	535,879
Total Capitalization and Liabilities	$2,452,935	$2,268,289	$2,361,476	$2,456,151	$2,446,954	$2,444,142

*Reclassified for comparative purposes.

Financial Data

At December 31	1998	1997	1996	1995	1994	1993
Capitalization Ratios(a) (percent)						
Long-term debt	49.8	43.0	44.7	47.4	48.2	49.4
Preferred stock	4.2	5.2	6.9	7.3	7.3	6.6
Common shareholders' equity	46.0	51.8	48.4	45.3	44.5	44.0
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$20.94	$20.80	$20.24	$19.71	$19.78	$19.70
Rate of Return on Average Common Equity (b) (percent)	11.22	11.00	11.41	8.37	8.92	10.25
Embedded Cost of Senior Capital (percent)						
Long-term debt	7.20	7.32	7.33	7.38	7.40	7.36
Preferred stock	5.56	5.80	6.26	6.26	6.26	6.69
Effective Federal Income Tax Rate (percent)	39.7	39.2	40.4	40.7	37.7	33.5
Depreciation Rate (percent)—Electric	3.09	3.12	2.99	2.76	2.69	2.62
—Gas	2.64	2.60	2.60	2.59	2.62	2.60
Interest Coverages						
Before federal income taxes (incld. AFUDC)	4.41	4.06	3.82	2.95	2.98	2.87
(excld. AFUDC)	4.38	4.04	3.79	2.90	2.94	2.84
After federal income taxes (incld. AFUDC)	3.06	2.86	2.68	2.16	2.24	2.24
(excld. AFUDC)	3.03	2.84	2.65	2.10	2.20	2.21
Interest Coverages Excluding Non-Recurring Items (c)						
Before federal income taxes (incld. AFUDC)	4.41	4.06	3.82	3.66	3.55	3.03
(excld. AFUDC)	4.38	4.04	3.79	3.61	3.51	3.00
After federal income taxes (incld. AFUDC)	3.06	2.86	2.68	2.62	2.61	2.35
(excld. AFUDC)	3.03	2.84	2.65	2.57	2.57	2.32

(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) Coverages for 1994 and 1993 exclude the effects of retirement enhancement programs recognized by the Company during each year and certain gas purchase undercharges 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	1998	1997	1996	1995	1994	1993
Electric Revenue (000's)						
Residential	$250,073	$252,464	$254,885	$256,294	$243,961	$234,866
Commercial	203,338	210,643	215,763	215,696	206,545	196,100
Industrial	130,778	144,305	153,337	157,464	150,372	148,084
Municipal and Other	58,889	72,061	66,898	67,128	57,270	59,905
Electric revenue from our customers	643,078	679,473	690,883	696,582	658,148	638,955
Wholesale electric sales*	44,022	20,856	16,885	25,883	16,605	16,361
Total electric revenue	687,100	700,329	707,768	722,465	674,753	655,316
Electric Expense (000's)						
Fuel used in electric generation	53,954	47,665	40,938	44,190	44,961	45,871
Purchased electricity	27,024	28,347	46,484	54,167	37,002	31,563
Other operation	195,400	205,058	204,746	199,524	192,360	192,749
Maintenance	38,022	41,217	41,429	44,032	47,295	52,464
Depreciation and amortization	102,123	103,395	92,615	78,812	75,211	72,326
Taxes—local, state and other	89,164	91,111	95,010	102,380	97,919	96,043
Total electric expense	505,687	516,793	521,222	523,105	494,748	491,016
Operating Income before Federal Income Tax	181,413	183,536	186,546	199,360	180,005	164,300
Federal income tax	61,477	61,837	61,901	59,500	52,842	43,845
Operating Income from Electric Operations (000's)	$119,936	$121,699	$124,645	$139,860	$127,163	$120,455
Electric Operating Ratio %	45.8	46.0	47.1	47.3	47.7	49.2
Electric Sales—KWH (000's)						
Residential	2,111,739	2,139,064	2,132,902	2,144,718	2,117,168	2,123,277
Commercial	2,007,282	2,118,991	2,061,625	2,064,813	2,028,611	1,986,100
Industrial	1,929,268	2,010,613	2,010,963	1,964,975	1,860,833	1,892,700
Municipal and Other	514,243	537,051	520,885	531,311	513,675	504,987
Total customer sales	6,562,532	6,805,719	6,726,375	6,705,817	6,520,287	6,507,064
Wholesale electric sales*	1,671,959	1,218,794	994,842	1,484,196	1,021,733	743,588
Total electric sales	8,234,491	8,024,513	7,721,217	8,190,013	7,542,020	7,250,652
Electric Customers at December 31						
Residential	309,931	308,909	307,181	306,601	304,494	302,219
Commercial	30,248	30,940	30,620	30,426	29,984	29,635
Industrial	1,279	1,300	1,325	1,347	1,361	1,382
Municipal and Other	2,594	2,824	2,688	2,711	2,670	2,638
Total electric customers	344,052	343,973	341,841	341,085	338,509	335,874
Electricity Generated and Purchased—KWH (000's)						
Fossil	1,962,889	1,664,914	1,512,513	1,631,933	1,478,120	1,520,936
Nuclear	5,323,639	5,119,544	4,094,272	4,645,646	4,527,178	4,495,457
Hydro	189,512	227,367	248,990	171,886	218,129	199,239
Pumped storage	232,927	238,900	246,726	237,904	247,550	233,477
Less energy for pumping	(348,438)	(358,350)	(370,097)	(361,144)	(371,383)	(355,725)
Other	195	890	936	1,565	1,245	2,559
Total generated—net	7,360,724	6,893,765	5,733,340	6,327,790	6,100,839	6,095,943
Purchased	1,376,221	1,301,636	2,437,433	2,343,484	1,998,882	1,646,244
Total electric energy	8,736,945	8,195,401	8,170,773	8,671,274	8,099,721	7,742,187
System Net Capability—KW at December 31						
Fossil	526,000	526,000	529,000	529,000	532,000	541,000
Nuclear	638,000	638,000	638,000	640,000	617,000	620,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	28,000	28,000	28,000	28,000	29,000	29,000
Purchased	349,000	375,000	375,000	375,000	375,000	347,000
Total system net capability	1,588,000	1,614,000	1,617,000	1,619,000	1,600,000	1,584,000
Net Peak Load—KW	1,388,000	1,421,000	1,305,000	1,425,000	1,374,000	1,333,000
Annual Load Factor—Net %	59.5	56.1	61.9	57.6	58.8	59.1

*Includes sales to energy marketers and bulk sales.

GAS DEPARTMENT STATISTICS

Year Ended December 31	1998	1997	1996	1995	1994	1993
Gas Revenue (000's)						
Residential	$ 2,944	$ 5,852	$ 6,010	$ 4,081	$ 5,935	$ 5,526
Residential spaceheating	201,686	249,101	246,945	230,934	215,974	201,129
Commercial	40,196	51,893	52,073	51,117	49,115	46,321
Industrial	4,222	5,800	6,175	6,686	7,088	6,368
Municipal and other	25,492	23,663	35,076	1,045	47,949	34,364
Total gas revenue	274,540	336,309	346,279	293,863	326,061	293,708
Gas Expense (000's)						
Gas purchased for resale	155,497	196,579	202,297	167,762	194,390	166,884
Other operation	63,014	63,416	61,348	59,684	49,312	47,593
Maintenance	5,188	5,418	5,634	5,194	7,774	9,229
Depreciation	12,867	13,127	12,999	12,781	12,250	11,851
Taxes—local, state and other	27,672	30,685	31,858	31,514	31,859	30,849
Total gas expense	264,238	309,225	314,136	276,935	295,585	266,406
Operating Income before Federal Income Tax	10,302	27,084	32,143	16,928	30,476	27,302
Federal income tax	(92)	3,442	7,600	6,715	8,403	5,485
Operating Income from Gas Operations (000's)	$ 10,394	$ 23,642	$ 24,543	$ 10,213	$ 22,073	$ 21,817
Gas Operating Ratio %	81.5	78.9	77.8	79.2	77.1	76.2
Gas Sales—Therms (000's)						
Residential	3,599	5,773	6,455	7,167	6,535	6,871
Residential spaceheating	239,740	285,395	299,085	280,763	283,039	295,093
Commercial	53,552	65,675	70,543	68,380	72,410	78,887
Industrial	6,079	7,828	9,334	9,560	11,420	12,030
Municipal	6,388	7,331	8,086	8,219	10,230	12,188
Total gas sales	309,358	372,002	393,503	374,089	383,634	405,069
Transportation of customer-owned gas	163,575	166,060	167,779	146,149	136,372	124,436
Total gas sold and transported	472,933	538,062	561,282	520,238	520,006	529,505
Gas Customers at December 31						
Residential	16,944	16,265	16,718	17,443	17,836	18,389
Residential spaceheating	249,684	243,264	240,685	238,267	235,313	231,937
Commercial	18,633	19,118	19,045	18,978	18,742	18,636
Industrial	778	829	857	879	905	924
Municipal	965	1,117	961	981	988	1,001
Transportation	1,900	836	744	655	558	466
Total gas customers	288,904	281,429	279,010	277,203	274,342	271,353
Gas—Therms (000's)						
Purchased for resale	203,677	274,430	279,353	237,728	262,267	347,778
Gas from storage	111,164	104,317	122,843	152,852	134,802	76,378
Other	1,496	1,410	1,082	1,800	2,959	1,039
Total gas available	316,337	380,157	403,278	392,380	400,028	425,195
*Total Daily Capacity—Therms at December 31**	4,380,000	4,380,000	4,480,000	5,230,000	5,625,000	5,625,000
Maximum daily throughput—Therms	3,583,500	4,114,290	4,022,600	3,980,000	4,735,690	3,864,850
Degree Days (Calendar Month)						
For the period	5,666	6,916	6,998	6,535	6,699	7,044
Percent colder (warmer) than normal	(15.9)	2.8	3.9	(3.0)	(0.6)	4.4

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

Investor Information

BUSINESS AND FINANCIAL INFORMATION
RG&E business and financial information is now available on line as well as by phone.

RG&E by Phone
Access RG&E from anywhere in the United States or Canada by calling our automated investor communications system at (800) 724-8833. You will be greeted with a brief message, then given a menu of options. Among other things, you can hear RG&E's quarterly earnings announcement or request a copy, including financial statements, by fax or by mail.

RG&E on Line
RG&E's web site now features electronic versions of our annual report and annual meeting, along with the latest news and financial information, including quarterly dividend and earnings announcements, financial statements and press releases. Visit us on line at *http://www.rge.com.*

RG&E Financial Information
Earnings results are typically released around the 23rd of January, April, July and October. Dividend announcements are made in March, June, September and December at mid-month.

Security Analyst Contact
Security analysts and others requesting information about RG&E should contact Thomas E. Newberry, Director of Investor Relations at (716) 724-8091.

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

SHAREHOLDER SERVICES
Shareholder services representatives are available weekdays from 9 a.m. to 6 p.m. eastern standard time through Boston EquiServe at (800) 736-3001. Among other things, they can provide dividend information, enroll you in our dividend reinvestment program and handle requests for ownership or account changes.

Stock Transfer Agent
BankBoston, N.A.
c/o Boston EquiServe
P.O. Box 8040
Boston, MA 02266-8040
(800) 736-3001

Telecommunication Device for the Deaf (TDD)
(800) 952-9245

DIVIDENDS
Dividend Payment Dates
Dividends on Common Stock are paid quarterly around 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. To enroll, you need to have ten shares of RG&E Common Stock and the shares have to be held in your name, meaning they can't be in a broker street name account.

FIRST MORTGAGE BOND TRUSTEE
Bankers Trust Company
c/o BT Services Tennessee Inc.
Securities Payment Unit
P.O. Box 291207
Nashville, TN 37229-1207
(800) 735-7777

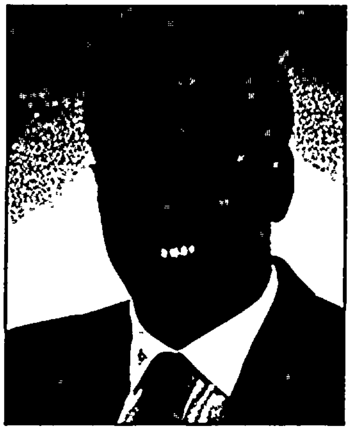
ANNUAL MEETING
RG&E's 1999 annual meeting of shareholders will be held at the Hyatt Regency Rochester, on Thursday, April 29, 1999 at 11 am.

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 RG&E's 1998 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by calling (800) 724-8833 or writing to Investor Services at RG&E.

Board of Directors and Officers

Board Appointment



Cleve L. Killingsworth, Jr.

Cleve L. Killingsworth, Jr. was elected to RG&E's board of directors in July 1998. He is president and chief executive officer of Health Alliance Plan that serves more than a half-million customers in Michigan and northern Ohio. Mr. Killingsworth also has held senior management positions with other health care organizations, including the Rochester-based Blue Cross and Blue Shield of Western New York. He is a graduate of M.I.T. and Yale University.

Board of Directors

(as of January 1, 1999)

Angelo J. Chiarella †ˎ
Former Vice President,
Rochester Midtown, L.L.C.

Allan E. Dugan *‡
Executive Vice President,
Business Group Operations,
Xerox Corporation

Mark B. Grier †
Executive Vice President,
Financial Management,
The Prudential Insurance Company of America

Susan R. Holliday ˎ
President and Publisher,
Rochester Business Journal

Jay T. Holmes *ˎ
Attorney and Commercial Arbitrator

Samuel T. Hubbard, Jr. †‡
Former President and Chief Executive Officer,
The Alling and Cory Company

Cleve L. Killingsworth, Jr.
President and Chief Executive Officer,
Health Alliance Plan

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

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

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

Charles I. Plosser *‡
Dean and John M. Olin Distinguished Professor of Economics and Public Policy of the William E. Simon Graduate School of Business Administration, University of Rochester

Thomas S. Richards *
Chairman of the Board, President and Chief Executive Officer,
Rochester Gas and Electric Corporation

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

Officers

(as of January 1, 1999)

Thomas S. Richards
Chairman of the Board, President and Chief Executive Officer
Age 55, Years of Service, 7

J. Burt Stokes
Senior Vice President, Corporate Services and Chief Financial Officer
Age 55, Years of Service, 3

Michael T. Tomaino
Senior Vice President and General Counsel
Age 61, Years of Service, 1

Paul C. Wilkens
Senior Vice President, Generation
Age 51, Years of Service, 25

David C. Heiligman
Vice President and Corporate Secretary
Age 58, Years of Service, 35

Robert C. Mecredy
Vice President, Nuclear Operations
Age 53, Years of Service, 27

Wilfred J. Schrouder, Jr.
Vice President, Human Resources
Age 57, Years of Service, 36

William J. Reddy
Controller
Age 51, Years of Service, 31

Mark Keogh
Treasurer
Age 53, Years of Service, 27

Jessica S. Raines
Auditor
Age 41, Years of Service, 3

Energetix, Inc.

Michael J. Bovalino
President and Chief Executive Officer
Age 43, Years of Service, 2

John A. Hamilton
Vice President, Operations
Age 44, Years of Service, 1

Printed on recycled paper.

RG AND E

hester Gas and Electric Corporation
East Avenue, Rochester, NY 14649-0001
6) 546-2700
Equal Opportunity Employer