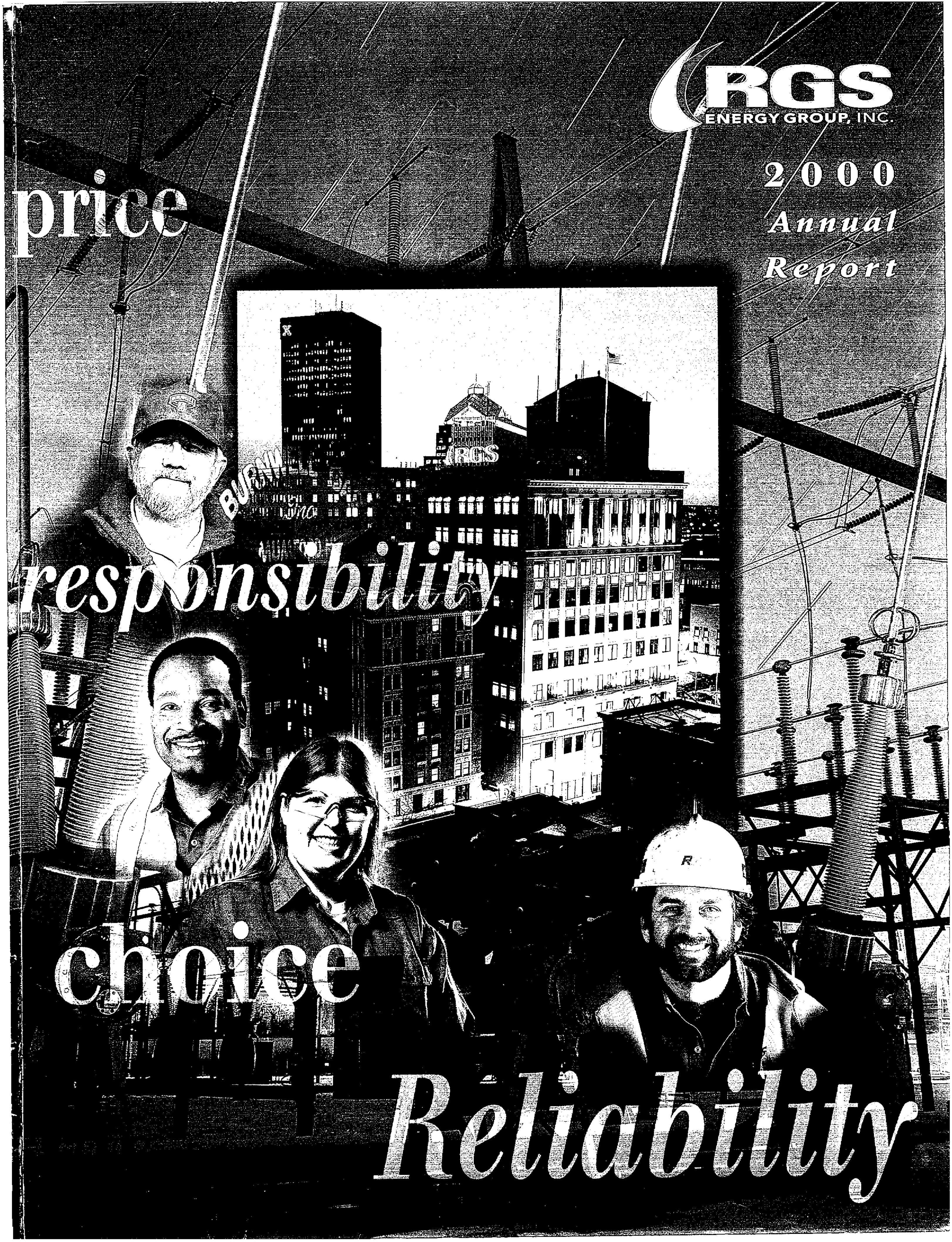

RGS
ENERGY GROUP, INC.
2000
Annual
Report
price
responsibility
choice
Reliability

Growing Towards the Future

RGS Energy Group, Inc. was formed in 1999 as a holding company in response to the deregulation restructuring in the energy utility business. Its regulated energy business is conducted through Rochester Gas and Electric Corporation (RG&E), and its unregulated business through Energetix. The vision at RGE Energy Group is to be the premier energy provider in the state. The mission is to provide energy and energy-related services to all of our customers with the highest level of satisfaction and quality.

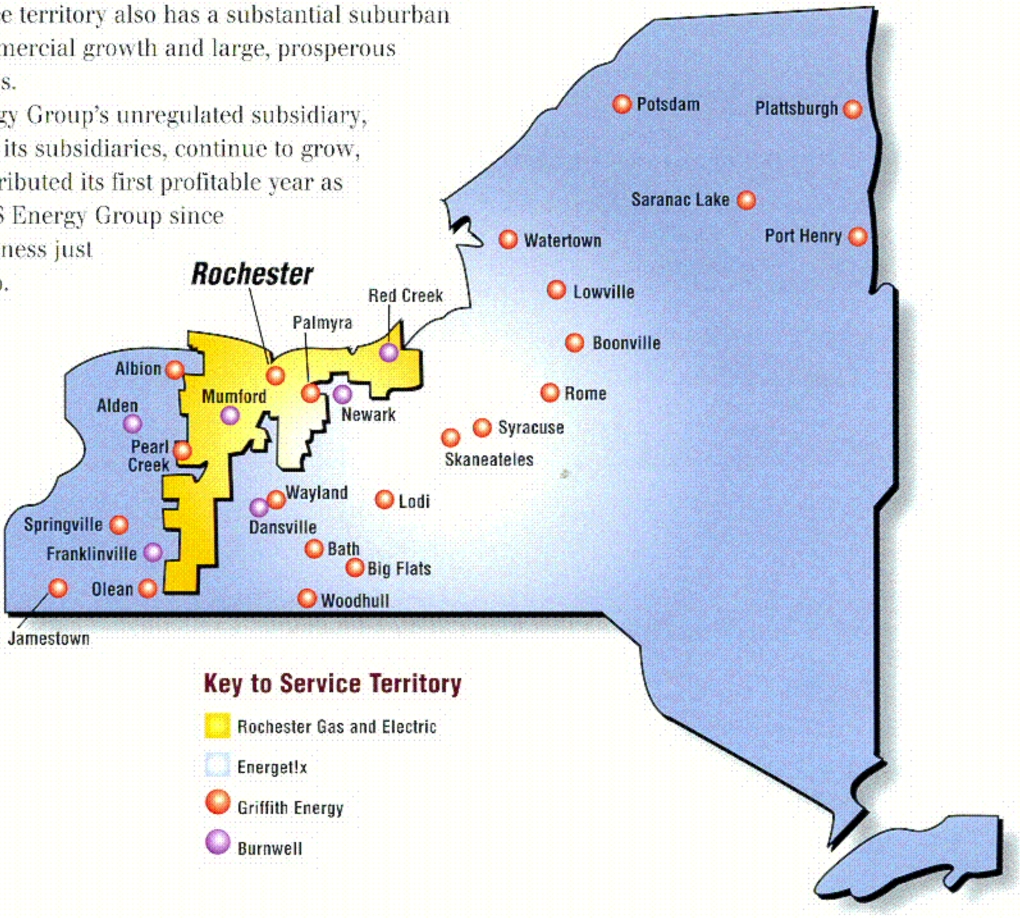
RG&E supplies regulated electric and gas service within a 2,700-square-mile service territory with a population of one million people. The service territory is well diversified among residential, commercial and industrial customers. The City of Rochester is the third largest in New York State and a major industrial center. Multinational commerce in the Greater Rochester Region makes this area the top exporting region outside of New York City. Projections of exports from the region are expected to reach nearly $15 billion in goods and services during the year ending 2000.

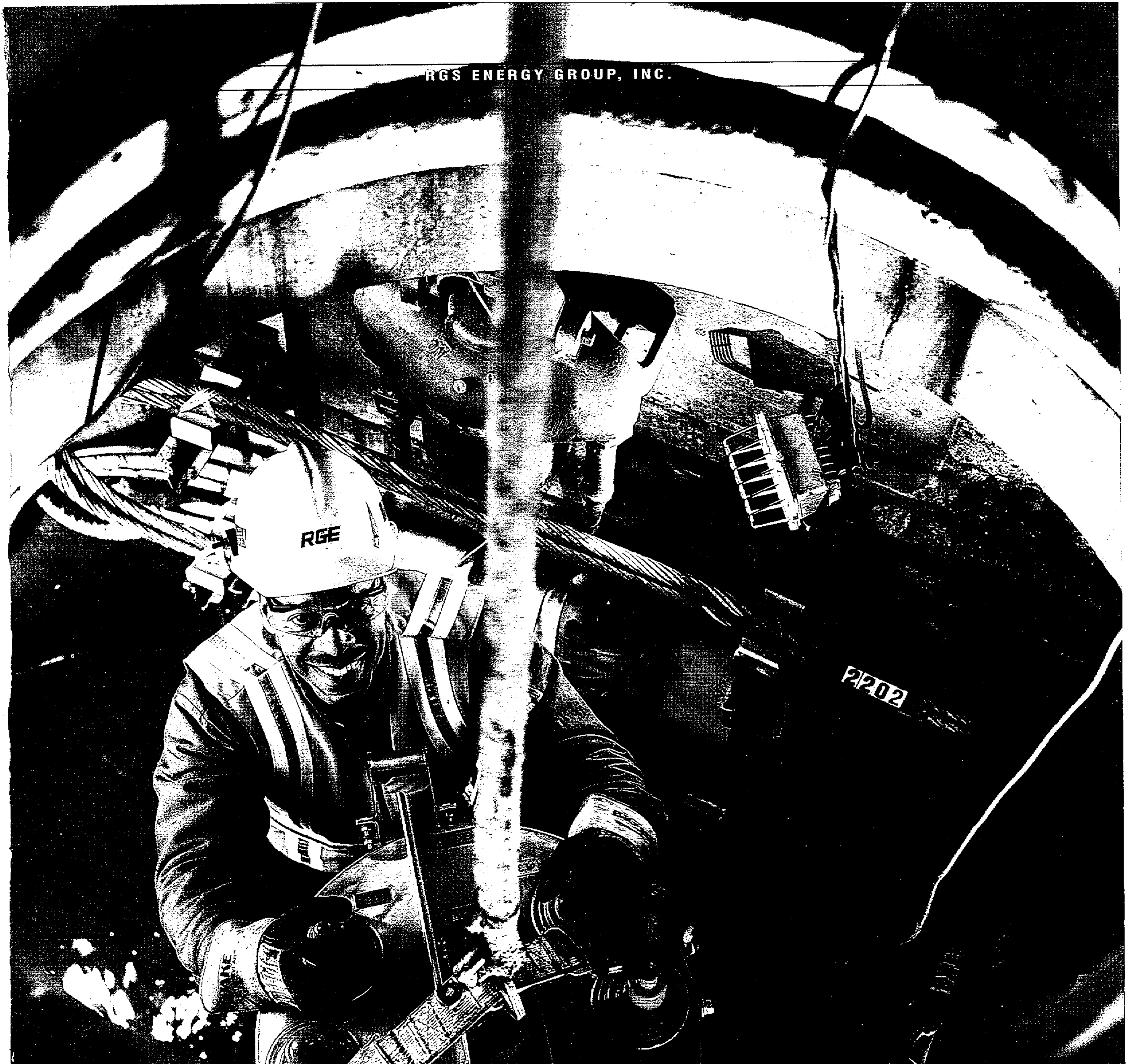
The service territory also has a substantial suburban area with commercial growth and large, prosperous farming regions.

RGS Energy Group's unregulated subsidiary, Energetix, and its subsidiaries, continue to grow, Energetix contributed its first profitable year as part of the RGS Energy Group since going into business just three years ago.

For Energetix the year 2000 was not only one of profitability but substantial expansion as well. Starting the year with 15,000 natural gas and electricity customers, it ended up with more than 86,000 customers throughout upstate New York.

By the end of year 2000, the Energetix subsidiary, Griffith Energy, completed an aggressive expansion program that acquired eight petroleum companies. The most significant of these strategic acquisitions included Burnwell® Gas, a large propane distributor, along with its wholesale sister company, Seimax Gas Corporation. Burnwell® is both a shipper on the TET pipeline from Mont Belvieu, Texas and through our Ontario, Canada transfer plant. The company is one of the largest, most reliable exporters of Canadian propane supply in the Northeast. Then through acquiring New York State Fuels Division of AllEnergy Marketing, L.L.C., Griffith Energy nearly doubled its customer base and now serves over 117,000 customers across the state.





RG&E spends nearly $100 million yearly to improve energy delivery systems; constructing substations, installing transformers, lightning arrestors, animal guard fences, radio controlled switches, and miles of gas pipeline. We're upgrading systems, already among the most reliable in the country. Everyday reliability is what we want for our customers, now and in the future. RG&E, always at your service.

2000 Revenue Dollar

Source of 2000 Revenue Dollar

Residential 34¢
(17¢ Electric, 17¢ Gas)

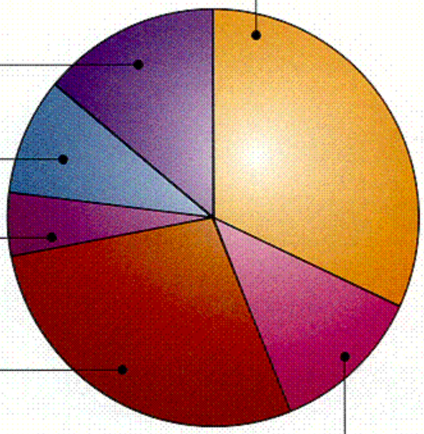
Commercial 13¢
(11¢ Electric, 2¢ Gas)

Industrial 8¢
(7¢ Electric, 1¢ Gas)

Other 5¢
(3¢ Electric, 2¢ Gas)

Unregulated
Operations 28¢

Wholesale
Electric 12¢



Use of 2000 Revenue Dollar

Unregulated
Operations 26¢

Purchased Gas 14¢

Other Operations 13¢

Taxes 11¢

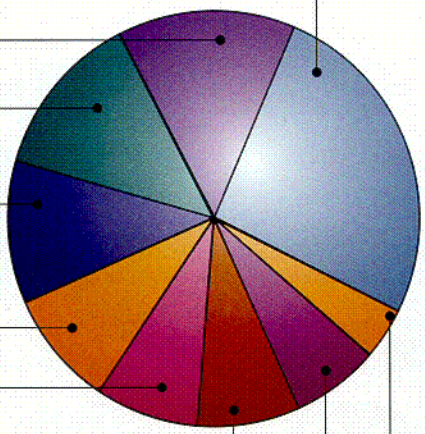
Electric Fuel
& Purchased
Electricity 9¢

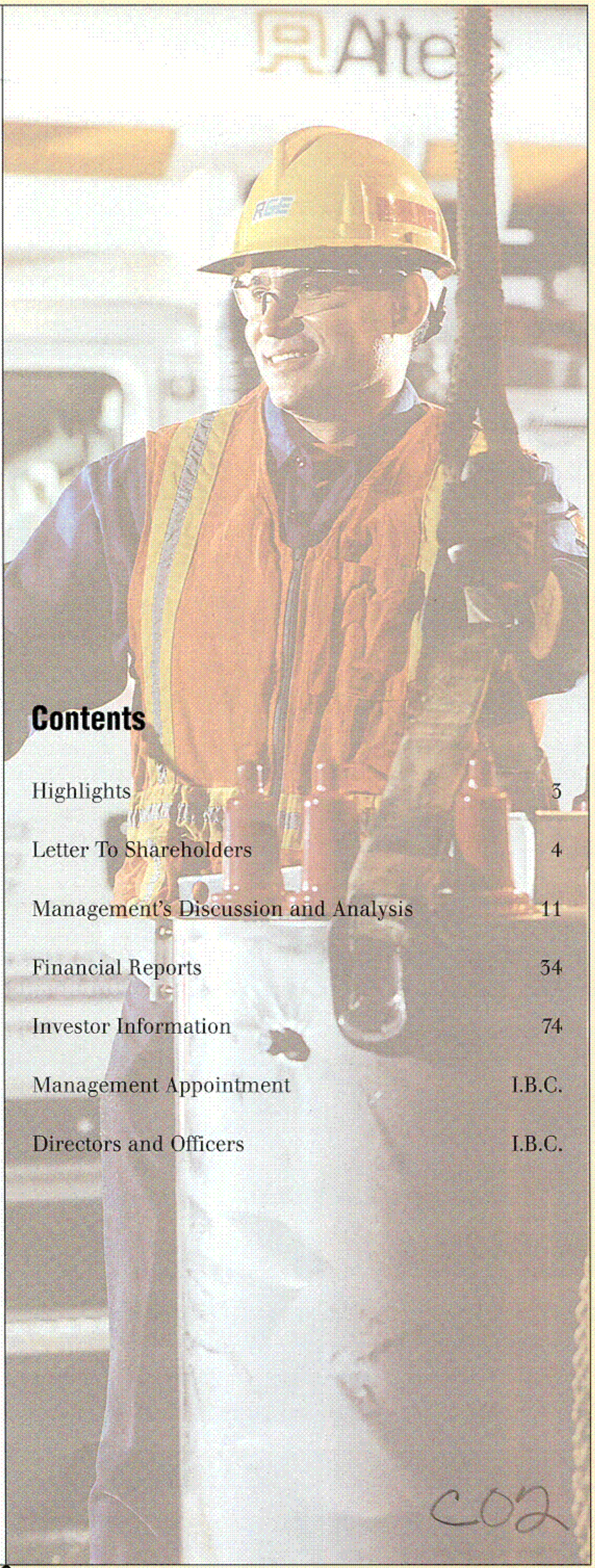
Wages & Benefits 8¢

Depreciation
& Amortization 8¢

Dividends
& Reinvested
Earnings 7¢

Interest 4¢





Contents

C02

Financial Highlights—RGS

	2000	1999	% Change
Financial Data (Thousands)			
Operating revenues: Electric	**$ 731,006**	$ 702,751	4
Gas	**$ 340,014**	$ 284,476	20
Other	**$ 377,099**	$ 220,310	71
Total	**$1,448,119**	$1,207,537	20
Operating expenses	**$1,299,041**	$1,066,619	22
Operating income	**$ 149,078**	$ 140,918	6
Net income applicable to common stock	**$ 91,859**	$ 89,497	3
Rate of return on average common equity	**11.82%**	11.53%	3
Common Stock Data			
Weighted average number of shares outstanding (Thousands)			
–Basic	**35,178**	36,665	(4)
–Diluted	**35,281**	36,757	(4)
Per common share:			
Earnings–Basic	**$2.61**	$2.44	7
Earnings–Diluted	**$2.60**	$2.44	7
Dividends Paid	**$1.80**	$1.80	—
Book Value (year end)	**$22.19**	$21.43	4
Year-end market price	**$32.44**	$20.56	58
Number of Registered Common Stock Shareholders at December 31	**25,518**	27,258	(6)
Operating Data			
Sales (Thousands)			
Kilowatt-hours to retail customers	**5,943,564**	6,319,259	(6)
Kilowatt-hours to wholesale customers	**2,770,518**	1,874,927	48
Therms of gas sold and transported	**594,177**	535,850	11
Net additions to utility plant, less allowance for funds used during construction (thousands)	**$ 142,496**	$108,339	32
Employees (year end)	**2,642**	2,354	12

To Our Shareholders,

The year 2000 was a turbulent one in the utility business, but a good one for RGS Energy Group. As I have written in these letters in the past, we need to balance the challenges that result from the fundamental change as our industry restructures and still keep the lights on and the gas flowing. That is what we did in 2000 – and we managed to do it while also producing improved financial results and shareholder value.

Despite the good results for RGS, we are concerned about the problems that have occurred in the restructured industry in California and, to a lesser extent, in New York. To address this concern, we have confined this letter to a discussion of the highlights for RGS in the year 2000 and included a discussion of broader industry issues in a separate section that follows.

RGS Energy Group Financial Performance

We earned $2.61 a share in 2000, up from $2.44 in 1999 and $2.32 in 1998. Many factors contributed to this favorable performance, but one of the most significant was the first contribution to our profit from Energetix, our unregulated energy business. The year 2000 started out poorly for utility sector stocks with RGS Energy's common stock hitting a low of $18.69 in late February. However, RGS finished the year with a very positive performance. Our stock closed the year at $32.44 with a total annual return, including dividends, of 69 percent. While our performance substantially mirrored the utility sector, not every company participated. Your investment in RGS was a good one in 2000.

Energetix

An important part of our strategy for success is building an energy service company through Energetix. It does business across upstate New York, offering electricity, natural gas, energy services and, through its Griffith Energy subsidiary, propane, home heating oil and other liquid fuels. The year 2000 was a successful one for Energetix, with a contribution of $484 million to RGS Energy revenues while posting its first profitable year since its creation just three years ago.

The year 2000 was not only profitable for Energetix, but one of substantial expansion as well. Starting the year with 15,000 natural gas and electricity customers, it ended up with more than 86,000.

> **RGS** *finished the year with a very positive performance... our stock closed the year with a total annual return of 69 percent.*

The Energetix subsidiary, Griffith Energy, was acquired in August 1998 and brought 70,000 liquid fuels customers. Since that date, we have continued an aggressive expansion program of eight liquid fuel company acquisitions. The most significant of these acquisitions occurred at the end of the year 2000 and included Burnwell Gas, a large propane distributor, and the New York State Fuels Division of AllEnergy Marketing L.L.C., a liquid fuels business. After these acquisitions, Griffith increased its customer base to 123,000. We expect to continue to profitably build on this base in 2001.

Nine Mile Nuclear

I reported in my 1999 letter that RG&E announced its intention to acquire a controlling interest in the Nine Mile Point nuclear power plants. We made that decision in response to an agreement by Niagara Mohawk and New York State Electric and Gas Corp. to sell their interests in the nuclear station to AmerGen. We believed the AmerGen sale, as proposed, did not justify the sale of our interest. On the contrary, by exercising our right to purchase the facilities under the proposed terms, the sales agreement provided us with an opportunity to guarantee our customers a reliable supply of electricity at stable prices, to transfer the operating risks and to pay off our outstanding debt.

With market conditions for the sale of nuclear power plants improving and several potential purchasers indicating interest, the agreement did not receive Public Service Commission (PSC) approval.

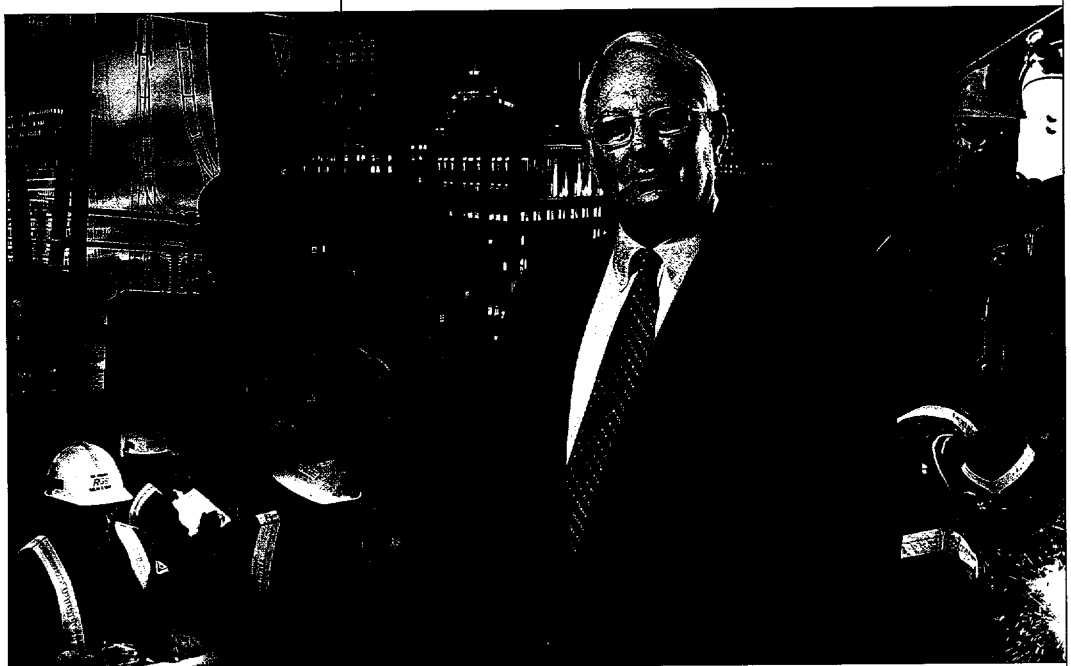
The Commission used the occasion to reaffirm its policy of having regulated utilities exit the generation business. At its urging, we agreed to develop a plan with our co-owners to determine the market value of the facilities through an auction process.

The results of the auction addressed many of our concerns. The price was substantially higher than the previous offer. The 10-year term of a power purchase agreement provides our customers with long-term price protection. RG&E will be relieved of the risks associated with operation of the plant, and the prospective purchaser is a respected and experienced nuclear plant operator.

This sale will not represent a windfall for RG&E. We have a substantial investment in the plant that will not be completely covered by the sale and this will have to be resolved as part of the regulatory proceeding to approve the sale.

While the auction phase has reached a successful completion, the proposed sale will require approval by several regulatory agencies. The responsibility rests with the PSC to determine whether the sale, as proposed, is in the public interest and provides the basis for fair regulatory treatment. This responsibility takes on added significance by virtue of the Commission's active encouragement of this process and the prevailing market conditions for electricity. We are optimistic that an acceptable regulatory outcome can be achieved.

RG&E will remain the owner-operator of the Ginna Nuclear Power Station. Ginna was not part of the sale process and the sale of Nine Mile Point Two has no effect on our ownership or operation of Ginna.



Thomas S. Richards

Natural Gas Prices

One disappointment in the year 2000 was the sharp increase in natural gas prices across the country – nearly quadrupling at one point. Several years of lower prices has discouraged production. In 2000, demand – partly influenced by increasing use of gas to generate electricity – began to outrun supply in a winter that started out colder than normal. While RG&E's gas distribution charge to customers has remained fixed since 1994, one third of our customers' gas bill consists of the cost of the gas commodity, so gas bills for our customers are higher this heating season. We don't profit from it and we don't like it, but we have managed the impact on our business successfully.

At the end of 2000, we reached a settlement proposal for setting our gas rates through June 2002, which will make it consistent with our electric rates agreement. We consider the proposal to be fair and reasonable and expect it to be acted upon by the PSC early in 2001. It is described in the Management Discussion Section of this Report.

Competitive Choice, Deregulation, Regulation

We continue the process of providing a choice of electric and gas retail suppliers to the customers of RG&E. By the end of the year 2000, nearly 40,000 electric customers representing 24 percent of our total electric supply and 41,000 gas customers accounting for some 54 percent of our gas demand were being provided energy by competitive suppliers. This is consistent with the original plan in our five-year regulatory settlement. However, the regulatory and industry changes that are necessary for the full development of retail competitive choice hit some snags in 2000. If we are to continue to make progress, there is some work to be done on a statewide and national basis. Our view of this situation and what needs to be done is contained in the discussion that follows this letter.

Our overall progress will continue to be measured by our ability to successfully adapt to a changing environment and we believe that we are in a good position to be flexible and to thrive.

A Reliable Future

In the 1999 Annual Report, I said that we were on a journey that leads less to a destination than to a state of continual change. On this journey, our progress was to be measured not by how near we are to a fixed location, but by our ability to successfully adapt to and prosper in this ever-changing environment. That was certainly true in the year 2000 and I expect nothing less in 2001.

In our regulated RG&E business in 2001, we expect to bring to a conclusion the disposition of the Nine Mile Point Two nuclear plant. We also will begin the process of working with the Public Service Commission and various other parties to determine the next steps in restructuring our regulated business that will occur after the end of our current regulatory agreement in June 2002. With substantial generation of our own, solid financial performance and a continuing commitment to improving reliability, we are in a good position to respond and to continue to produce good results.

In our unregulated business, Energetix, we are in a position to take those opportunities presented to us by the course of deregulation and the development of the wholesale markets and to continue the growth of our liquid fuels business. The liquid fuels business, which is now the largest part of Energetix, provides a basis for profitable growth that is not dependent on the uncertain development of electric deregulation and the electric and gas wholesale markets.

Our overall progress will continue to be measured by our ability to successfully adapt to a changing environment and we believe that we are in a good position to be flexible and to thrive.

Neil Murphy

The annual meeting this year will mark the retirement of Cornelius J. (Neil) Murphy after 20 years as a Director. Neil has been a valuable member of the Board and a valued counselor to me and many of my predecessors. The company appreciates his service and I appreciate his loyal support.

RGS Is On Track

I cited some goals in the last annual report. We wanted to balance the many challenges facing this business and, amidst what has been a turbulent year for electric deregulation, make the challenges work for our shareholders and for our customers. We're doing just that, and we intend to extend the momentum. I give credit to RGS employees. Nothing can happen without them. A few employees are pictured in this report. They and many others at RGS make all this work. Please join me in commending them for a job well done.

Thomas S. Richards
February 1, 2001
Chairman of the Board,
President and Chief Executive Officer

We've given a lot of thought at RGS to the deregulation problems that have emerged, as seen particularly in California. While we have avoided the intensity of those problems in our service territory, the situation does concern us. We've established a view on the situation that I'd like to share with you. I invite you to read the following analysis.

The Deregulation Dilemma—Issues and Answers

—Thomas S. Richards

In one of the states that claimed leadership in bringing competition to the energy utility industry, things aren't working out the way they were intended. News accounts tell almost daily of record high prices, power shortages and blackouts in California. Electric bills tripled in the San Diego vicinity, and the financial solvency of the largest investor-owned California power companies with fixed rates has been seriously impaired. After a summer of woes, Californians found no relief in what has become the winter of their discontent, so much so that the state's governor labeled deregulation "a colossal and dangerous failure." Closer to home in New York City, the problems haven't been as significant as in California, but power bills there last summer were sharply higher.

Like most New York power companies, California utilities were ordered to sell power plants to create an unregulated wholesale energy market. Now these companies have to buy much of their power on that unregulated market.

RG&E, based on our negotiated settlement agreement, worked it out so that we did not have to sell any power plants. So, as it turns out, our electric customers have been largely protected from the volatile, unregulated power market. Our customers further benefit from our agreement to continue to reduce electric rates.

So, what's the problem with deregulation?

Well, along with promise, rapid change also can spark unexpected events and disappointment. Until recently, almost everybody got their electricity and gas from regulated monopolies, systems that had been in place for more than a century. Customers couldn't choose their suppliers, and the regulated energy companies couldn't choose their customers. Utilities were responsible for figuring out how much more energy would be needed, and then making sure it was there on time, every time. The money needed to accomplish this was averaged and spread out over long periods of time, avoiding sudden price spikes.

There were advantages to that way of doing business. However, the system was often condemned as being monopolistic, bureaucratic, and unsympathetic to price signals and consumers' pocketbooks, particularly after electric power became more expensive in the 1980s. There were a number of causes, not the least of which was the use of utility rates to collect higher property and special energy taxes and fund social programs. The higher cost was irritating customers and hurting local economies, particularly in places like California and New York, where it was viewed as making the states economically uncompetitive. Deregulation, which had gained favor in several other industries, was seen as the answer.

The idea was to restructure into three parts:

- Traditional, regulated businesses that deliver energy to all customers, maintain the "pipes and wires" and handle emergencies.
- Unregulated retail businesses that compete to sell energy and services.
- Unregulated owners of power plants that sell in an open market. Of all the factors, this one caused most of the recent price problems.

You need two things to create a competitive electric supply market. One is an organization to administer the bulk transmission systems that move power around the states and regions – something the regulated power companies used to do themselves. Now called an Independent System Operator (ISO), it has to provide an open marketplace for buying and selling power to all competitors, while maintaining the reliability of a system in which demand is constantly and instantly changing. Start-up problems in operating the ISOs have caused increased prices with very damaging price spikes. Many of those problems rise from overly optimistic estimates about how fast change could be made.

Then, of course, you need competitors for competition. Under the old system, generating plants were owned by power companies or the government. So to create a competitive power market the regulated power companies were told to sell their power plants to unregulated businesses, and then buy power back on the wholesale marketplace created by the ISOs. The thinking was that the open market would drive prices down for consumers in a way that hadn't happened with regulated monopolies.

Start-up problems in operating the Independent System Operators have caused increased prices with very damaging price spikes.

What happened?

We think that some expectations and assumptions underlying this orchestrated change simply overestimated what can be done and how soon. While we believe competition can bring consumers better value, we also know that it doesn't always produce lower prices or guarantee the lowest price to everybody all of the time. Once you move from regulation to competition, you can't just order prices to be lower if you expect the system to work and the lights to stay on.

It wasn't simply a matter of selling the power plants. A number of other things also had to happen and there are other factors at work that affect the price and availability of electric energy:

- Taxes for some past regulatory decisions and social-program funding contribute significantly to higher costs. These costs still are substantially with us.
- Prices for the fuels, particularly natural gas, that fire power plants in many areas, have climbed to unexpected, even record highs.
- It was assumed once-ample electric capacity would meet demand for years and that selling power plants to independent power producers would drive prices down in the marketplace until demand grew. That's a key assumption that turned out to be wrong. It was particularly disastrous in California and harmful as well in downstate New York, where the economy has been growing strongly and the ability to import electricity is limited by the availability of transmission capabilities. So, at times of high demand, the price of electricity was driven to unheard-of levels.
- Then, too, there is a fair amount of "regulation" still in deregulation. In California, for example, the investor-owned power companies were prohibited from negotiating long-term power contracts from power producers to moderate short-term fluctuations. In both New York and California, the process of siting and building power plants to add supply is heavily regulated, difficult and takes a long time. When demand grew and supply got tight, it was very difficult to add new generation. Very little has been added in California or New York for many years and no plants are fully permitted or under construction in New York today.

It's not that deregulation can't work; it's just that we have some work to do before it will work. Deregulation is going to take time. We shouldn't ignore recent events as momentary or insignificant, but use them to teach us what to do and set realistic expectations.

So what do we do?

> *Reliability cannot be assumed. It takes an adequate complement of qualified people and constant, substantial investment.*

Adopt, stick to and judge what we are doing by a set of values that realistically reflects what people want and should receive from the energy utility industry. At RGS Energy we believe those values and their order of importance are:

1. Reliability
2. Price
3. Choice
4. Community Responsibility

We place reliability first and believe our customers do as well because the others simply don't mean much when you're working in the dark. We're not saying that we never change the order of these values, but we do have to consider consequences whenever we do. For instance, most people would agree that some level of environmental regulation is appropriate even though it increases the price of electricity and may slow the process for building new power plants. Community social programs and taxes add to costs as well. It is not that these added costs are wrong. What's wrong is to ignore their impact on cost and the competitive market. With these values in mind, and believing that reliability is foremost, as any Californian will attest, we should do the following in New York:

Sensibly and with due environmental concern, we must add new generation to our statewide system to meet growing demand. That will mean streamlining the approval process.

We need to develop the ability to have our use of power respond to limits in supply and high cost. Immediately, this means a system of voluntary use reduction by larger users that can be implemented quickly and counted on. This will allow us, particularly in the downstate area where this is a more serious problem, to reduce demand when supplies get tight.

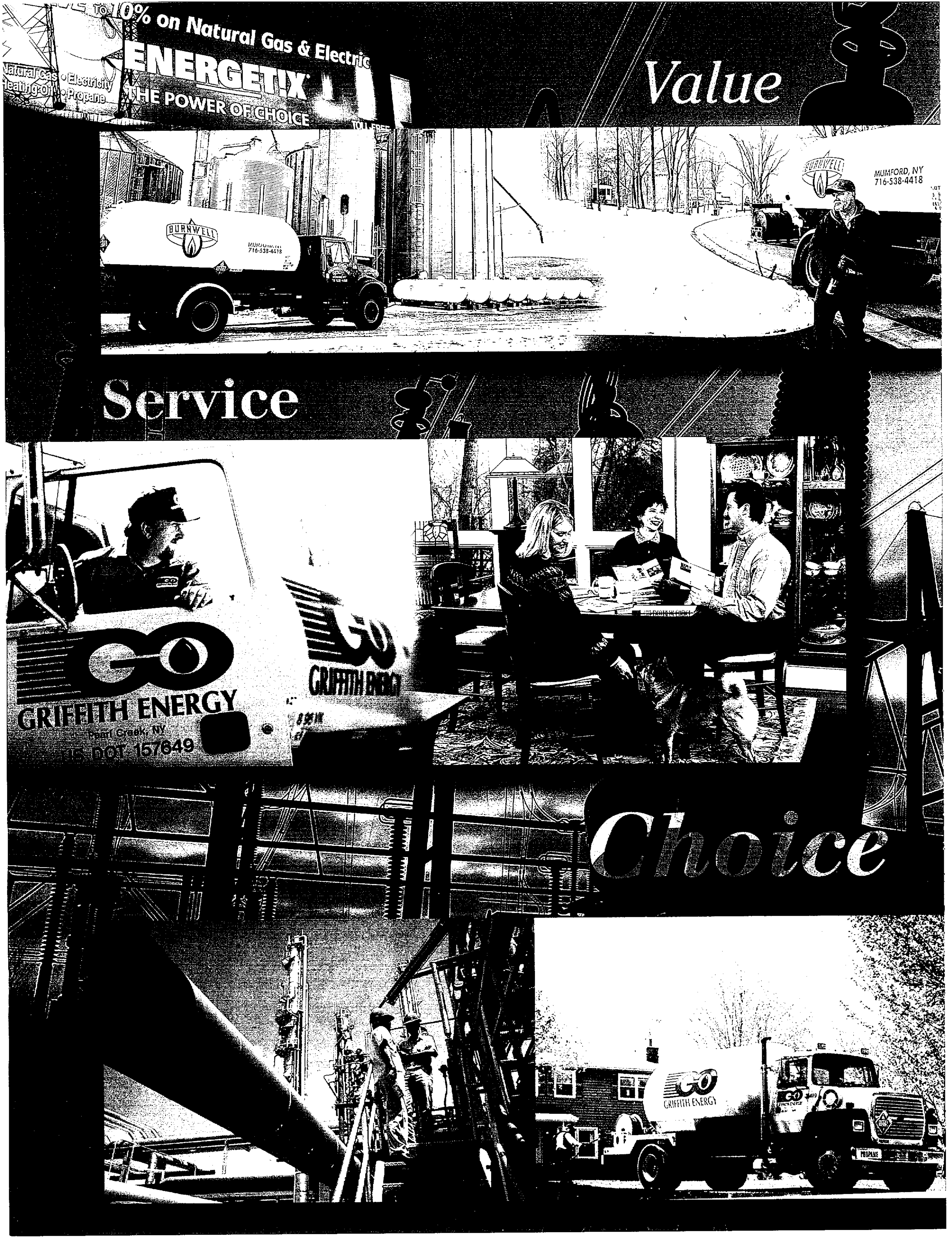
We must place reasonable temporary controls on an immature and not fully functional competitive market for power to prevent abuses or taking advantage of supply limitations.

Over time, we need to adjust the way we use and make electric energy. This can involve many aspects of efficient use; conservation; response to the real time actual cost of energy; reducing dependence on one fuel source, such as gas; and new, sometimes more environmentally friendly, ways of generating electricity. Important though they are, these approaches, even collectively, are not enough. They will take time and their impact is difficult to predict. In the near term, most of them increase the cost of energy. We need to be realistic about what we can or are willing to accomplish and the resulting impact on our economy. If we are not realistic, these approaches are likely to be a victim, rather than a result, of a crisis, as many are today in California

We should be willing to convert slowly and thoughtfully to a deregulated environment, and not be afraid or ashamed to correct our course and make adjustments where needed. In short, we must never confuse politics with the physics behind the requirement for reliable, available and reasonably priced electricity. California teaches us that we cannot anticipate everything that will influence electric supply and demand. A competitive market may be the right future of electric supply, but it is not a miracle and the transition is important and will take time.

Reliability cannot be assumed. It takes an adequate complement of qualified people and constant, substantial investment. If we try to make up for the supply problems or subsidize the competitive choice programs by driving down the distribution rates, we will eventually pay for it in decreased reliability. We should be working on ways to increase the investment in the distribution system and that is what we are doing at RG&E.

This annual report reflects our commitment to the values that should guide the electric utility industry and the primacy of reliability among the values. No matter where the course of energy competition leads this nation, we do not think that should change.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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 RGS Energy Group, Inc. and its subsidiaries over the past three years. The Consolidated Financial Statements and the Notes thereto contain additional data. For the twelve months ended December 31, 2000, 50 percent of the Company's operating revenues were derived from electric service, 22 percent from natural gas service, and 28 percent from unregulated businesses.

Selected Abbreviations and Glossary

Cooling degree days: A measure that quantifies the extent to which the daily outdoor average temperature exceeds a base of 65 degrees Fahrenheit. One degree day is counted for each degree day falling above the assumed base for each calendar day.

Company or RGS: RGS Energy Group Inc., a holding company formed August 2, 1999,which is the parent company of Rochester Gas and Electric Corporation, RGS Development Corporation, and Energetix, Inc.

FERC: Federal Energy Regulatory Commission

Ginna Plant: Ginna Nuclear Plant which is wholly owned by RG&E

Heating degree days: A measure that quantifies the extent to which the daily outdoor average temperature falls below a base of 65 degrees Fahrenheit. One degree day is counted for each degree day falling below the assumed base for each calendar day.

Nine Mile Two: Nine Mile Point Nuclear Plant Unit No. 2 of which RG&E currently owns a 14% share

PSC: New York State Public Service Commission

Regulatory Assets: 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

RG&E: Rochester Gas and Electric Corporation, a wholly-owned subsidiary of the Company

Electric Settlement: 1997 Competitive Opportunities Case Settlement among RG&E, PSC and other parties which provides the framework for the development of competition in the electric energy marketplace through June 30, 2002

SFAS: Statement of Financial Accounting Standards

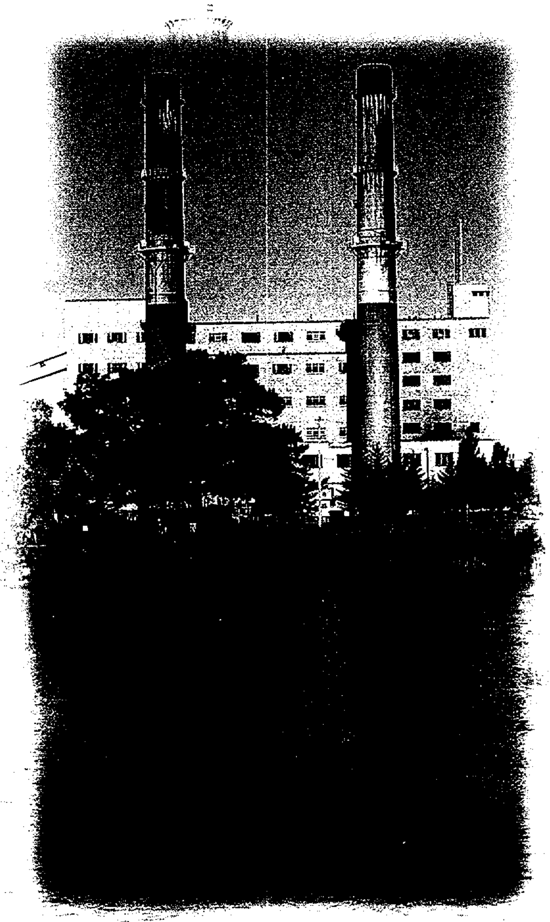
FORWARD LOOKING STATEMENTS

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 effect on whether the forward looking statements ultimately prove to be accurate include:

1. uncertainties related to the regulatory treatment of RG&E's nuclear generation facilities including the proposed sale of RG&E's interest in the Nine Mile Two nuclear generating facility;
2. any state or federal legislative or regulatory initiatives (including the results of negotiations between RG&E and the PSC regarding certain gas restructurings) 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;

3. any changes in the ability of RG&E to recover environmental compliance costs through increased rates;
4. the determination in the nuclear generation proceeding initiated by the PSC, including any changes in the regulatory status of nuclear generating facilities and their related costs, including recovery of costs related to spent fuel and decommissioning;
5. fluctuations in energy supply and demand and market prices for energy, capacity and ancillary services;
6. any changes in the rate of industrial, commercial and residential growth in RG&E's and RGS's service territories;
7. the development of any new technologies which allow customers to generate their own energy or produce lower cost energy;
8. any unusual or extreme weather or other natural phenomena;
9. the timing and extent of changes in commodity prices and interest rates;
10. the ability of RGS to manage profitably new unregulated operations;
11. certain unknowable risks involved in operating unregulated businesses in new territories and new industries; and
12. any other considerations that may be disclosed from time to time in the publicly disseminated documents and filings of RGS and RG&E.

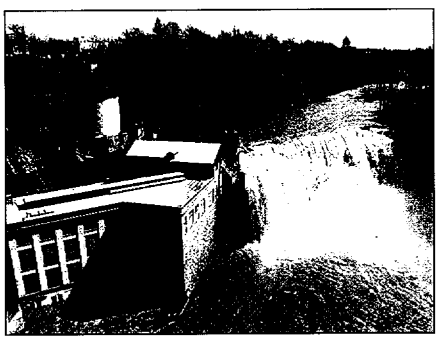
Shown below is a listing of the principal items discussed.



RGS Energy Group, Inc.

On August 2, 1999, RG&E was reorganized into a holding company structure pursuant to an Agreement and Plan of Share Exchange between RG&E and RGS. As part of the reorganization, all of the outstanding shares of RG&E common stock were exchanged on a share-for-share basis for shares of RGS and RG&E became a subsidiary of RGS. RG&E's preferred stock was not exchanged as part of the share exchange and continues as shares of RG&E.

The holding company structure was formed to enable RGS to respond quickly to changes in the evolving competitive energy utility industry. The new structure permits the use of financing techniques that are better suited to the particular requirements, characteristics and risks of non-utility operations without affecting the capital structure or creditworthiness of RG&E. This increases RGS's financial flexibility by allowing it to establish different debt-to-equity ratios for each of its individual lines of business.



Station #5, hydro generating plant.

RGS is a holding company and not an operating entity. RGS's operations are being conducted through its subsidiaries which include RG&E and two unregulated subsidiaries – Energetix, Inc. and RGS Development Corporation. RG&E will continue to offer regulated electric and natural gas utility service in its franchise territory. Energetix, Inc. provides energy products and services primarily throughout Upstate New York. RGS Development Corporation offers energy systems development and management services.

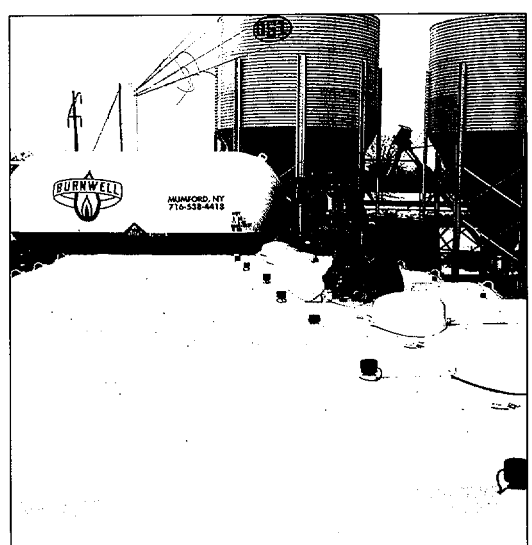
Unregulated Subsidiaries. Part of RGS's financial strategy is to seek growth by entering into unregulated businesses. The Electric Settlement allows RG&E to provide the funding for RGS to invest up to $100 million in unregulated businesses and RGS has invested $87 million (including loan guarantees) as of December 31, 2000. The first step in this direction was the formation and operation of Energetix, Inc. (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 throughout Upstate New York. Energetix has over 83,000 customers for natural gas and electricity service.

In August 1998, Energetix acquired Griffith Oil Company, Inc. (Griffith), the second largest oil and propane distribution company in New York State. This $31.5 million acquisition was accounted for using purchase accounting and the results of Griffith's operations are reflected in the consolidated financial statements of RGS since its acquisition on August 2, 1998.

In November 2000, Griffith acquired Burnwell® Gas, a full-service propane gas retailer and distributor providing fuel, appliances, heating equipment and service in the Western New York area. This acquisition adds 29,000 customers to the Griffith customer base. The acquisition was accounted for using purchase accounting and Burnwell® Gas's results of operations are reflected in the consolidated financial statements of RGS since the acquisition.

In November 2000, Griffith also acquired certain assets of the New York Fuels Division of AllEnergy Marketing Company, L.L.C., related to its petroleum distribution business. This acquisition adds 24,000 customers to the Griffith customer base. The acquisition was accounted for using purchase accounting and the results of the acquired operations are reflected in the consolidated financial statements of RGS since the acquisition.

Griffith and its recent acquisitions as discussed above give Energetix access to over 123,000 customers, approximately 100,000 of whom are outside of RG&E's regulated franchise territory. Acquisitions by Griffith since August 1998 have increased its customer base by over 100 percent. In total, Griffith has approximately 620 employees and operates 28 customer service centers as of December 31, 2000.



A Burnwell agricultural customer, where multiple propane tanks are used to dry grain.

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

During the second quarter of 1998, the Company formed RGS Development to pursue unregulated business opportunities in the energy marketplace. Through December 31, 2000, RGS Development's operations have not been material to RGS's results of operations or its financial condition.

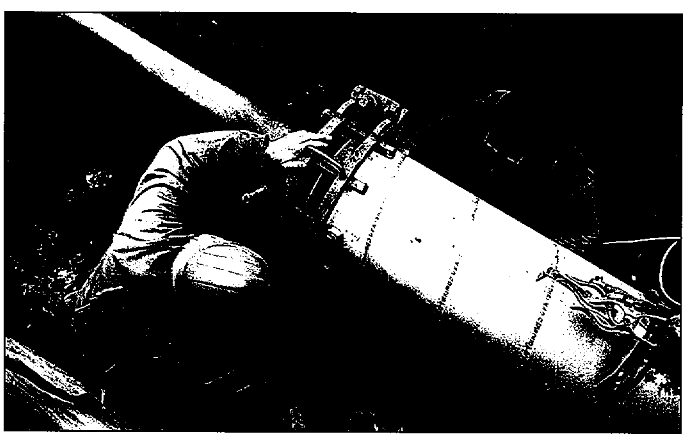
Rochester Gas and Electric Corporation

Competition

Gas Retail Access Settlements.

On January 25, 2001, RG&E reached agreement with PSC Staff and other parties on a comprehensive rate and restructuring proposal for its natural gas business (the Gas Rates and Restructuring Proposal), as contemplated in the PSC's Gas Policy Statement (see heading Rates and Regulatory Matters, "PSC Gas Restructuring Policy Statement").

Since mid-1998, RG&E, PSC Staff and other parties have engaged in settlement negotiations regarding RG&E's rates and restructuring. These negotiations have resulted in two previous agreements among RG&E, PSC Staff and several other parties. The first was implemented in September 1999 and addressed the following issues: a capacity release revenue imputation, capacity cost mitigation measures, a timetable for public filing and resumption of negotiations, and improvement of RG&E's retail access program. The September 1999 agreement was approved by the PSC in an Order issued September 30, 1999.



RG&E continues to strengthen infrastructure with the installation of miles of new gas pipeline. Here workers join two lengths of 16" diameter pipe.

Pursuant to the September 1999 agreement, RG&E, on January 28, 2000, made a filing addressing various issues pertaining to RG&E's natural gas business, including proposals for restructuring that business and facilitating migration from fully bundled sales service to retail service provided by natural gas marketers. Certain issues presented by the January 28, 2000 filing, principally relating to the commencement of a single-retailer retail access program for gas, in substantially the same form as currently in effect for electric retail access (see "Energy Choice" heading), and the establishment of a "backout credit" to be paid to natural gas marketers serving retail customers, were resolved in a June 2000 Gas Settlement.

The Gas Rates and Restructuring Proposal is intended to resolve all issues identified by the parties and not resolved in either the September 1999 settlement or the June 2000 Gas Settlement, as approved by the PSC. It is anticipated that this Proposal will be approved by the PSC in February 2001 and made effective on March 1, 2001, although no assurance may be given as to such approval or its timing.

The Gas Rates and Restructuring Proposal contains a number of features that are intended to extend for different periods. The two most significant periods are the Rate Term, which applies principally to rate-related provisions and extends from July 1, 2000 through June 30, 2002, and the Rate and Restructuring Program which applies to most other provisions and extends from the date of approval of the Proposal through March 31, 2004. The principal features of the Proposal are as follows:

(1) for the purpose of setting base, or local delivery, rates for the period beginning July 1, 2000, natural gas revenues shall be decreased a total of $2,806,000 from the levels in effect on June 30, 2000. This rate level is based on an agreed-upon return on equity of 11.00 percent;

(2) base rates will be adjusted effective March 1, 2001 to reflect the revenue requirements decrease. Because the current base rates that will be in effect through February 28, 2001 are higher than those agreed to by the parties, RG&E, in March 2001, will pass back to all its retail gas customers a temporary credit applied to rates, on a volumetric basis, equal to the amount of the reduction in rates for the period July 1, 2000 through February 28, 2001;

(3) RG&E is allowed to defer any prudent and verifiable cost for recovery after the Rate Term of the Proposal, subject to PSC approval;

(4) in the event that RG&E achieves a return on equity in excess of 12.5 percent in any Rate Year covered

by this Proposal, 90 percent of the excess over that level shall be deferred for the benefit of customers;

(5) RG&E shall be entitled to defer any costs associated with mandates and catastrophic events that occur during the Rate Term of this Proposal. If the incremental cost impact of any individual mandate or any individual catastrophic event exceeds $600,000 per rate year, RG&E is entitled to defer the entire amount for recovery. Amounts deferred shall be recovered from RG&E customers after the Rate Term of this Proposal;

(6) RG&E is entitled to defer for recovery after June 30, 2002, all incremental expenditures for competition implementation costs to the extent that such costs exceed $300,000 per year;

(7) if migration to retail access is expected to exceed 30 percent of the small-volume customer market (i.e., customers eligible under Service Classification No. 5 – Small General Service) during the Rate Term of the Proposal, the parties will meet to discuss the PSC Transition Cost Surcharge with a view to considering changes that would reduce the allocation of capacity costs to Service Classification No. 1 – General Service customers;

(8) RG&E is authorized to implement a Retail Access Capacity Program, contemplated to begin before the 2001-2002 heating season, pursuant to which RG&E would release pipeline capacity it currently holds to marketers serving customers in RG&E's service area. This Program will help to avoid stranded capacity costs that might otherwise result from migration of customers to marketers;

(9) RG&E will implement a Capacity Incentive Program, consisting of a Capacity Cost Incentive and a Capacity Cost Imputation. Both elements are intended to encourage aggressive management of RG&E's capacity costs. The Capacity Cost Incentive is designed to share, between RG&E and its customers, the savings resulting from the difference between a base level of capacity costs and the actual capacity costs achieved. The Capacity Cost Imputation is intended to provide customers with a guaranteed level of short-term savings through the gas cost adjustment provision. "Short-term" refers to periods of one year or less. "Savings" refers to capacity release savings, as well as net revenues from off-system sales, if any. The imputed level of savings will be $1,100,000 per year for the period beginning April 1, 2001 and extending through June 30, 2002. The level will then be $500,000 per year for the period beginning July 1, 2002 and extending through March 31, 2004;

(10) RG&E will implement a Low-Income Program for customers who require assistance. The Low-Income Program will be funded through a surcharge in customer bills; and

(11) RG&E will implement a Service Quality Performance Program to be effective as of January 1, 2001 through at least June 30, 2002. This Program establishes performance targets for six specific measures of service and provides for a maximum overall penalty of 42 basis points of gas return on equity for failure to meet the minimum levels specified.

Gas Retail Access Program.

On December 1, 2000, RG&E implemented the single-retailer system for small volume gas customers, following the approval of a tariff filing with the PSC. Under the June 2000 Gas Settlement discussed above, RG&E is permitted to recover the difference between the backout credit paid marketers ($3.75 per customer per month) and RG&E's short-run avoided costs associated with the migration of gas sales customers to retail access under the single retailer system. For purposes of the June 2000 Gas Settlement, this assumed difference was set at $2.55 per customer per month. Both the backout credit and the assumed difference are to remain in effect at these levels over the term of the Settlement (generally through June 30, 2002), subject to possible further negotiations in the event of a particularly rapid migration of customers.

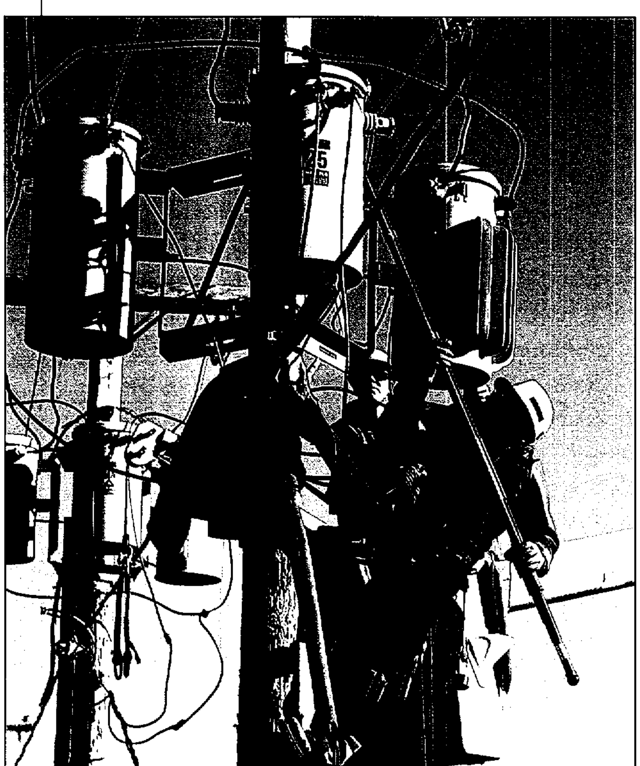
As of December 31, 2000, seventeen energy service companies, including Energetix, are qualified by RG&E to serve retail gas customers under RG&E's Gas Retail Access Program.

RG&E attempts to mitigate its risks of energy marketer defaults by requiring security deposits as permitted by PSC Transportation Gas Customer tariffs.

PSC Electric 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 (Electric Settlement). The Electric Settlement sets the framework for the introduction and development of open competition in the electric energy marketplace and lasts through June 30, 2002. 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 Electric Settlement sets RG&E's electric rates for each year during its five-year term. Over the five-year term of the Electric 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.



In the event that RG&E earns a return on common equity in its regulated electric business in excess of an effective rate of 11.50 percent over the entire five-year term of the Electric Settlement, 50 percent of such excess will be used to write down deferred costs accumulated during the term of the Electric Settlement. Any remaining amounts of this 50 percent shall be retained as earnings by RG&E. The other 50 percent shall be used to write down accumulated deferrals or investment in electric plant or regulatory assets (the Return on Equity Test). (See the discussion under "Results of Operations - 2000 Compared to 1999" regarding Management's estimate of return on equity reserves established in accordance with the terms of the Electric Settlement.) 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 RG&E or any other party to the Electric Settlement would have the right to petition the PSC for review of the Electric Settlement and appropriate remedial action.

The Electric Settlement requires unregulated energy retailing operations to be structurally separate from the regulated utility functions. Although the Electric Settlement provides incentives for the sale of generating assets, it does not require RG&E to divest generating or other assets or to write off stranded costs.

RG&E believes that the Electric Settlement has not adversely affected its eligibility to continue to apply certain accounting rules applicable to regulated industries. In particular, RG&E believes it continues 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. The Electric Settlement provides RG&E a reasonable opportunity to recover substantially all of its prudently incurred costs, except certain operational costs associated with non-nuclear generation.

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

Energy Choice.

On July 1, 1998, RG&E officially began implementation of its full-scale electric retail access Energy Choice program. As of July 1, 2000, RG&E entered its third year of this program. There are five basic components of the sale of energy as follows:

(1) the sale of electricity which is the amount of energy actually used by the consumer;

(2) the sale of capacity which is the ability, through generating facilities or otherwise, to provide electricity when it is needed;

(3) the sale of transmission services, which is the physical transportation of electricity to RG&E's distribution system;

(4) the sale of distribution services, which is the physical delivery of electricity to the consumer over RG&E's distribution system; and

(5) retail services such as billing and metering.

Historically, RG&E has sold all five components bundled together for a fixed rate approved by the PSC.

The implementation of Energy Choice included a four year phase-in process to allow RG&E and other parties to manage the transition to electric competition in an orderly fashion. During the first year of the program, participation in Energy Choice was limited to no more than 10 percent of RG&E's total annual retail electric kilowatt-hour sales (670,000 annualized megawatt-hours). Essentially, until this 10 percent limit was achieved, RG&E's electric retail customers could seek out or be approached by alternative energy service companies for electricity to be resold and then delivered over RG&E's distribution system. By February 1, 1999, only six months into the Energy Choice program, this 10 percent limit was achieved by qualified competitive energy service companies in RG&E's service territory. For the second year of the program, beginning July 1, 1999, this limit increased from 10 percent to approximately 20 percent. As of July 1, 2000, beginning the third year of the program, this limit increased to 30 percent. As of December 31, 2000, approximately 24 percent of total RG&E sales had shifted to competitive energy service companies, including the Company's unregulated subsidiary Energetix. Beginning July 1, 2001, all retail customers will be eligible to purchase energy, capacity and retailing services from competitive energy service companies. Throughout the term of the Electric 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 such service.

Energy Choice adopted the single-retailer model for the relationship between RG&E 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. Except for providing emergency services, satisfying requests for distribution services, and scheduling outages, which remain RG&E's responsibility, the retail customer's primary point of contact for billing questions, technical advice and other energy-related needs, is with the customer's chosen energy service company.

An RG&E employee performs an acceptance test of a network protector mechanism that will be installed on a network transformer and put into service in a downtown location.

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).

RG&E attempts to mitigate its risks of energy marketer defaults by requiring security deposits as permitted by PSC Electric Distribution Customer tariffs.

As of December 31, 2000, seven energy service companies, including Energetix, are qualified by RG&E to serve retail customers under Energy Choice.

During the initial Energy-Only stage of the Energy Choice program, which began on July 1, 1998 and ended on November 18, 1999, energy service companies were able to choose their own sources of energy supply, while RG&E continued to provide to them, through its bundled distribution rates, the generating capacity (installed reserve) needed to serve their retail customers. In addition, during the Energy-Only stage, energy service companies had the option of purchasing "full-requirements" (i.e., delivery services plus energy) from RG&E.

During the initial Energy-Only stage of the retail access program, RG&E's distribution rate was set by deducting approximately 2.31 cents per kilowatt-hour from its full service (bundled) rates. The 2.31 cents per kilowatt-hour was comprised of 1.91 cents per kilowatt-hour (an estimate of the wholesale market price of electricity) plus 0.40 cents per kilowatt-hour for RG&E's avoided cost of retailing services.

During the Energy and Capacity stage, which began on November 18, 1999, RG&E's distribution rates equaled the bundled rate less RG&E's cost of both the electric commodity and its non-nuclear generating capacity. Throughout this stage of the program, up until June 30, 2000, RG&E's distribution rates were set by deducting 3.07 cents per kilowatt-hour from its full service rates. The 3.07 cents per kilowatt-hour is comprised of 2.67 cents per kilowatt-hour (an estimate of the wholesale market price of electric energy and capacity) plus 0.40 cents per kilowatt-hour for its avoided cost of retailing services. Beginning July 1, 2000, RG&E's distribution rates were set by deducting 3.08 cents per kilowatt-hour from its full service rates. The 3.08 cents per kilowatt-hour is comprised of 2.68 cents per kilowatt-hour for energy and capacity plus 0.40 cents per kilowatt-hour for its avoided cost of retailing services. This change in the distribution rates, set by deducting 3.07 cents per kilowatt-hour and then 3.08 cents per kilowatt-hour, is a result of pre-determined changes in average gross receipts taxes.

RG&E people conduct field relay tests to help ensure system reliability.

The Energy and Capacity stage, the second stage of the phase-in, began with the implementation of the New York Independent System Operator on November 18, 1999 (see discussion under "New York Independent System Operator"). The responsibility for purchasing not only energy, but also capacity, was to have shifted to the energy service companies. However, the PSC and FERC had also approved a request by RG&E to extend "full-requirements" availability to energy service companies through the current winter capability period (from October 31, 2000 through April 30, 2001). As of December 31, 2000, all energy service companies serving customers under retail access have opted to continue purchasing "full requirements" through the current winter capability period.

Through April 30, 2001, energy service companies will have the option to serve a portion or all of their load from the competitive wholesale market, but once they make this change, they will not be able to return this load to "full requirements". Once RG&E no longer provides "full requirements" to the energy service companies, they will assume responsibility for obtaining their own supplies. RG&E will experience a revenue decrease when it no longer collects the rates described above for energy and capacity. This will be offset to some extent by decreased costs resulting from no longer acquiring energy and capacity for the energy service companies. The extent of this offset will be determined by market prices.

In December 1999, two petitions were filed with the PSC, one by an electric utility operating in New York State and the other jointly by five energy marketers and consultants, calling upon the PSC to examine RG&E's retail access program and to order certain changes in the program. In particular, these petitioners objected to the single-retailer form of RG&E's program, under which the retail marketer assumes responsibility for most retail service functions. They claim that the "back-out credit" (the amount by which RG&E's rates for retail electric service are reduced to derive the rates charged for the delivery service provided by RG&E to marketers) is too low, that it affords insufficient prospect of profitable operation by marketers, and that it should be increased. They further assert that the phased schedule for implementation of the program, under which increasing percentages of customers in RG&E's service area are eligible to obtain competitive service during the term of the Electric Settlement, is too slow and should be significantly accelerated. On February 28, 2000 RG&E filed with the PSC its reply to both petitions. As set forth in that reply, RG&E believes that its single-retailer program offers unique opportunities for marketers, that its retail backout credit (in conjunction with RG&E's rate for wholesale power sales to marketers) affords a sound basis for competitive service, and that its implementation schedule is reasonable and appropriate; moreover, each of these essential elements of the retail access program is expressly established by the Electric Settlement. RG&E believes that the program fully and fairly

advances the goals of increased competition for energy services and is in full compliance with the Electric Settlement. Nevertheless, it is not possible at this time to predict with assurance whether or not, in response to the petitions, the PSC might require that the program be changed in some manner.

The PSC is conducting proceedings that are intended to bring more administrative consistency among New York State utilities and potentially offer additional services for energy service companies to provide. These include an on-going national effort regarding uniform business practices, and proceedings regarding standardized billing (single billing options), provider of last resort, electronic data interchange, and competitive metering. RG&E continues to assess the scope and impact of such changes on its operations as retail access continues to evolve.

Nine Mile Nuclear Plants.

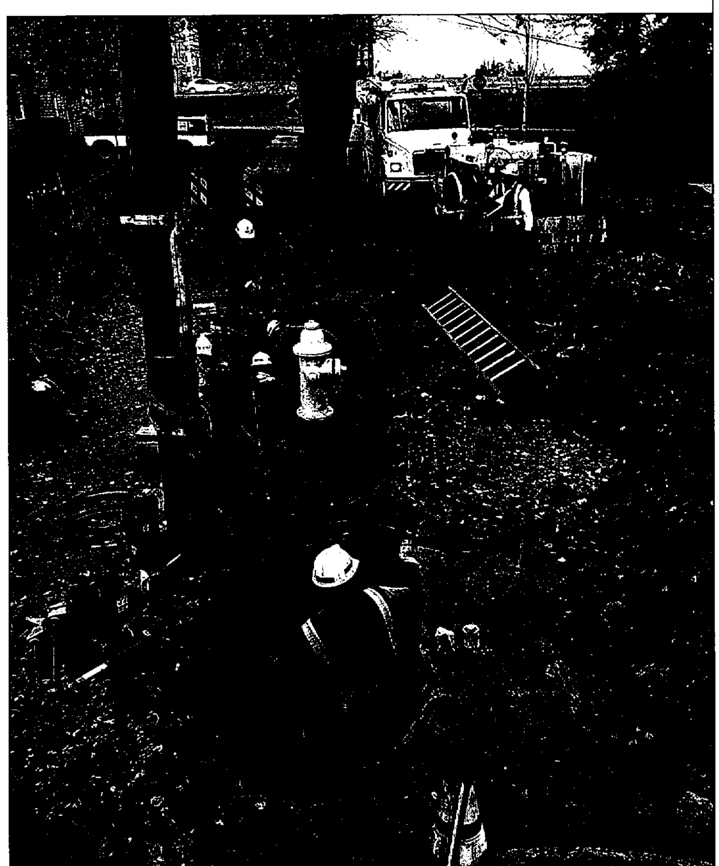
On June 24, 1999, Niagara Mohawk and New York State Electric and Gas Corporation (NYSEG) announced their intention to sell their interests in the Nine Mile One and Nine Mile Two nuclear plants to AmerGen Energy Company, L.L.C. (AmerGen), a joint venture of PECO Energy and British Energy. Niagara Mohawk owns 41 percent of Nine Mile Two and 100 percent of Nine Mile One and NYSEG owns 18 percent of Nine Mile Two.

RG&E's 14 percent interest in Nine Mile Two was not included in the proposal but RG&E has a right of first refusal to buy the interests of the other owners of Nine Mile Two on terms at least as favorable as those offered. RG&E exercised its right of first refusal and broadened it to include Nine Mile One with which Nine Mile Two was paired in the proposal. However, in the ensuing discussions with the PSC staff it became clear that the transaction on the terms proposed would not be approved by the PSC.

On April 25, 2000, the PSC issued an order that allowed NYSEG and Niagara Mohawk to withdraw their petition to sell their interests in the Nine Mile plants to AmerGen. The order concluded that Nine Mile's market value is "greatly in excess of the original AmerGen purchase price" and that multiple entities are now interested in the Nine Mile plants. The order also concluded that "...failure for the utilities to determine the market value of the Nine Mile facilities at this time, through an open process, would raise serious prudence questions." With respect to stranded costs, the PSC order indicates that stranded costs cannot be finally quantified "until the disposition of the plants by the utilities is decided." The PSC's order does, however, observe that (1) a sale would be considered within its policy of separating generation from transmission and distribution, (2) a sale at current market values would constitute appropriate mitigation of stranded costs and (3) ratemaking treatment of a sale would be resolved in accordance with each company's competitive opportunities/restructuring order taking into account reduced risk and corollary divestiture effects.

After issuance of the PSC's order, RG&E decided to determine the market value of its interest in Nine Mile Two. On June 1, 2000, RG&E issued a press release announcing an auction process by RG&E, Central Hudson Gas & Electric Corporation (Central Hudson), NYSEG and Niagara Mohawk in connection with their ownership interests in Nine Mile Two and Niagara Mohawk's interest in Nine Mile One.

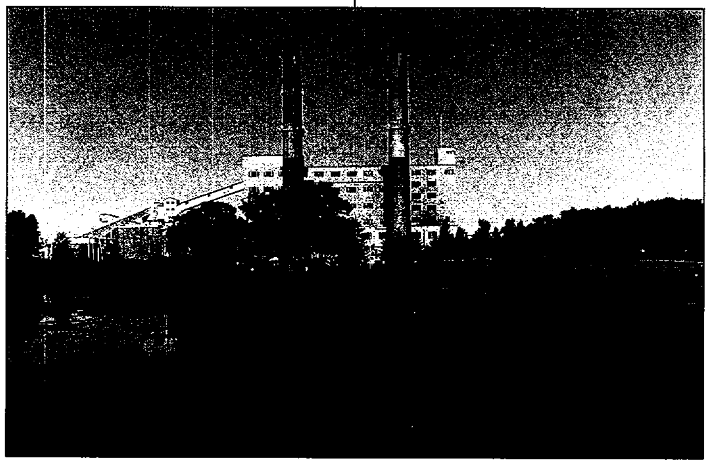
On December 11, 2000, RG&E, Niagara Mohawk, Central Hudson and NYSEG entered into an agreement to sell their ownership interests in Nine Mile Two to Constellation Nuclear, L.L.C. (Constellation Nuclear). Constellation Nuclear was the successful bidder in a competitive auction conducted for the plants. The Long



Soil corrosion and sinkage around new water hydrants can cause stress cracks to gas piping. A gas field operations crew creates a temporary bypass to keep a neighborhood in service while a section of cast iron gas line is replaced with new 13" steel.

Island Power Authority, an 18 percent owner of Nine Mile Two, is not participating in the sale.

The purchase price for RG&E's 14% ownership interest in Nine Mile Two is $99.2 million, $49.6 million of which will be paid in cash at closing and $49.6 million of which will be paid in five equal annual principal installments plus interest at a rate of 11% pursuant to a five year promissory note. Principal and interest payments under the promissory note will total approximately $66 million unless the note is pre-paid. The purchase price is subject to adjustment at the time of closing. The aggregate purchase price for 82 percent of Nine Mile Two is $581 million. The aggregate purchase price, including cash payments at closing and payments of principal and interest to all of the sellers under the promissory notes, is $676.6 million for 82 percent of Nine Mile Two.



Russell Station, an RG&E coal-fired power plant providing reliable electric power to customers since 1948.

Also, part of the transaction is a power purchase agreement whereby Constellation Nuclear has agreed to sell 90 percent of RG&E's 14 percent interest in Nine Mile Two's actual output back to RG&E for approximately 10 years at an average price of less than $35 per MWh over the term of the power purchase agreement.

After the completion of the power purchase agreement, a 10-year revenue sharing agreement begins. The revenue sharing agreement will provide RG&E with a hedge against electricity price increases and could provide RG&E additional revenue through 2021. The revenue sharing agreement provides that, to the extent market prices (for energy and capacity) exceed certain strike prices, 14% of the market value of Nine Mile Two's actual output (capped at 160 MW) above the strike price will be shared 80% to RG&E and 20% to Constellation Nuclear. When actual market prices are lower than strike prices, such negative amounts will be carried forward as credits against subsequent payments.

At closing, the sellers' pre-existing decommissioning funds will be transferred to Constellation Nuclear and Constellation Nuclear will assume the sellers' obligation to decommission Nine Mile Two.

The Nuclear Regulatory Commission (NRC), FERC, PSC and other regulatory bodies must approve the sale. Receipt of such regulatory approvals (including, without limitation, the PSC's authorization to establish a regulatory asset and return thereon for the full amount of RG&E's unamortized plant and capital costs of Nine Mile Two remaining after the closing of the sale), in form and substance reasonably satisfactory to RG&E, is a condition to RG&E's obligation to close the transaction. The transaction is targeted to close in mid-2001. At December 31, 2000, the net book value of RG&E's 14 percent interest in the Nine Mile Two generating facility was approximately $360 million. RG&E also had investments in fuel of approximately $8.9 million, transmission and distribution facilities of $3.4 million and construction work in progress of 4.6 million.

On January 31, 2001, RG&E, together with Niagara Mohawk, Central Hudson, NYSEG and Constellation Nuclear filed a Section 70 petition with the PSC. The petition requests that the PSC authorize the sellers to transfer to Constellation Nuclear their interests in Nine Mile Two in accordance with the rate treatment proposed. For RG&E, the rate treatment proposed includes full recovery of the regulatory asset remaining after the sale.

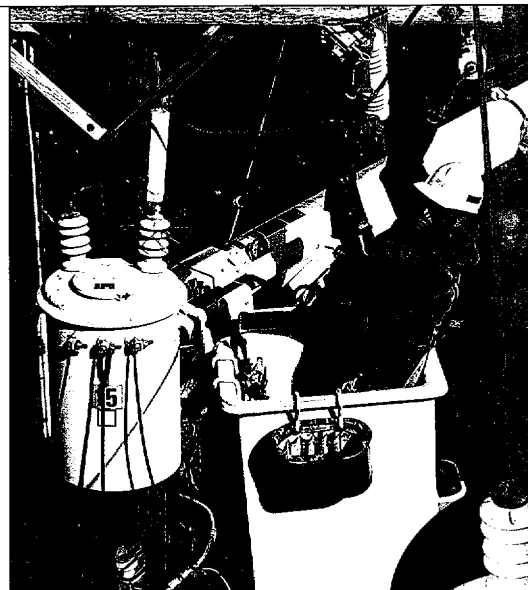
Prior to the events discussed above, the PSC had initiated a proceeding to examine the appropriate role of the nuclear power plants in the State in developing a competitive market for electricity. Collaborative efforts of the parties led to the development of a report on the subject which the PSC discussed at a July 1999 session without issuing an order. No significant activity has since occurred in the proceeding and RG&E cannot predict what the PSC may do to continue or conclude it. Since all nuclear plants in the State either have now been sold or are under contract to be sold, except for RG&E's Ginna Plant, the PSC could regard the proceeding as moot.

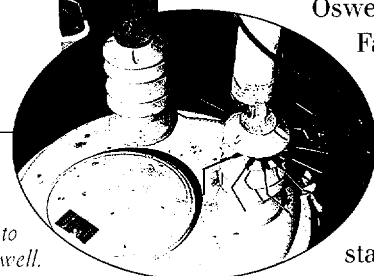
Fossil Units Status.

In 1999, RG&E ceased operations at and retired its Beebee Station (80 Megawatt) coal-fueled generating facility. The retirement of Beebee Station did not have a material effect on the financial position or results of operations of RGS or RG&E. The Electric Settlement provides that all prudently incurred incremental costs associated with the retirement and decommissioning of the plant are recoverable through RG&E's distribution access rates.

In early June 1999 the Allegany Station, a combined-cycle unit fueled by natural gas, began generating electricity. The 63 megawatt capacity unit is expected to generate electricity during the peak demand summer months and when the economics of producing electricity for sale are favorable. The plant is being operated and maintained for RG&E by Bell Harbert Energy L.L.C. Allegany Station, which was built as a co-generation facility in the early 1990s, was obtained by RG&E as part of a legal settlement in December 1998 with General Electric Capital Corporation, Kamine/ Besicorp Allegany L.P. (Kamine) and other Kamine affiliates.

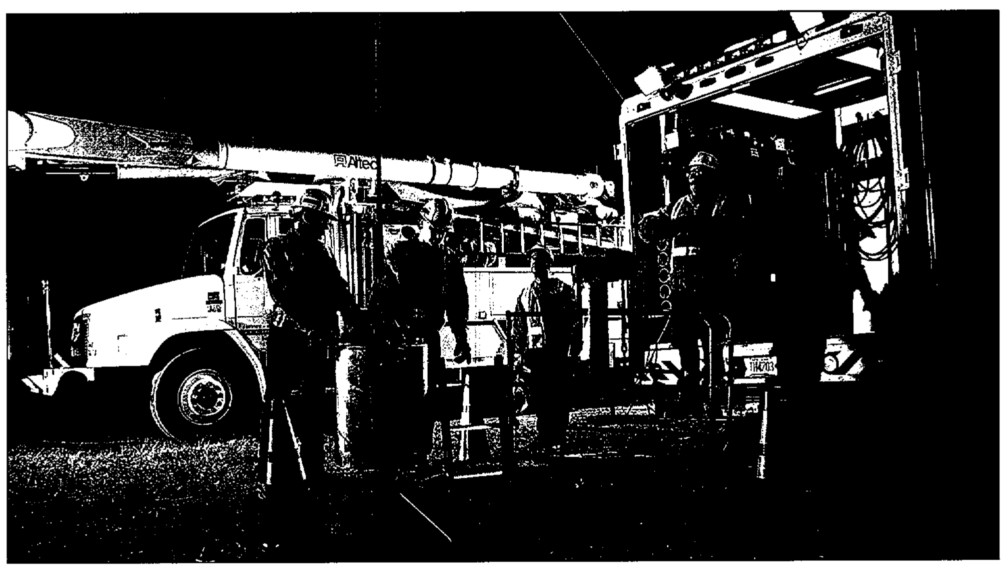
Oswego Unit Sale. On October 22, 1999, RG&E and Niagara Mohawk sold their respective 12% and 88% interests in the Oswego Generation Facility to Oswego Harbor Power L.L.C., a wholly-owned affiliate of NRG Energy, Inc. for approximately $91 million. Additionally, the buyer agreed to assume RG&E's obligations under a June 8, 1998 transmission services agreement as it pertains to the Oswego Generation Facility. This assumption represents a net present value of approximately $25 million, which was deducted from RG&E's approximately $11 million share of the sale proceeds. Accordingly, RG&E was required to make a net payment of approximately $14 million in connection with the sale. Under the terms of the Electric Settlement, RG&E is permitted to recover through its distribution rates any losses and related costs on a sale of generation. Pursuant to an October 21, 1999 PSC order, RG&E was required to file with the PSC a detailed calculation of its net book loss after tax impacts. RG&E made this filing with the PSC on December 21, 1999. Including the impact of the $25 million relating to the transmission services agreement, RG&E's net loss and associated costs are approximately $79 million. In the filing, RG&E indicated that $2.2 million of depreciation charges and $4.3 million of transmission contract payments, currently included in rates, will be used to amortize the net loss during the remaining term of the Electric Settlement.





An RG&E lineman installs an animal deterrent device to prevent power outages. The device harmlessly prevents animals from causing outages to customers, and protects the animals as well.

At the time of the sale of the Oswego Generating Facility, RG&E and Niagara Mohawk also entered into a contract for the sale of RG&E's interest in a 345 kilovolt substation at the Oswego site to Niagara Mohawk for $1.1 million. Approval of the transaction was received from both the PSC and FERC and the sale is currently pending. The net proceeds will be used to offset the loss which has been deferred as an regulatory asset.



Installing an underground switch using several of our new fleet vehicles, and our new radio controlled 'Digger Derrick'.

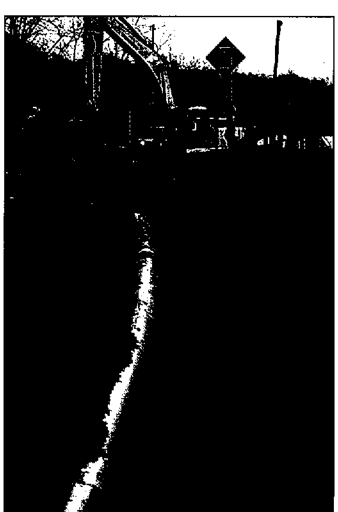
New York Independent System Operator.

In November 1999 following FERC approval, the New York State Independent System Operator (NYISO) sought to implement a competitive wholesale market for the sale, purchase and transmission of electricity and ancillary services in New York State. NYISO tariffs provide market-based rates for energy, ancillary services, and installed capacity sold through the NYISO. The NYISO and the New York State Reliability Council were formed to restructure the New York Power Pool in response to FERC Order 888.

In early 2000, the NYISO's total cost of providing operating reserves on an hourly basis exceeded the cost that would be expected in a workable competitive marketplace. During the first quarter of 2000, RG&E, in addition to other New York State public utilities and several load-serving entities, experienced rising prices to maintain operating reserves within the NYISO system. As a result of, among other things, the implementation of bidding restrictions that limit reserve prices, as discussed in the following two paragraphs, the average cost per MWH for operating reserves in the third and fourth quarters decreased to $.65 and $.38, respectively.

Many miles of gas pipe were replaced last year using wrapped steel on poly pipe for reliability and longevity.

On March 27, 2000, the NYISO filed with FERC for immediate authority to suspend the use of market-based bids in the New York markets for operating reserves. On April 7, 2000, RG&E also filed a complaint with FERC against the NYISO. RG&E sought corrective re-calculation of operating reserve prices for prior periods and prospective relief from injuries resulting from the NYISO's operating reserves market. Niagara Mohawk and NYSEG filed similar complaints with FERC against the NYISO. On May 31, 2000 FERC issued an order accepting the NYISO's request and capped prices for the 10-minute non-spinning reserve market at $2.52/MWH. In response to various complaints, FERC directed the NYISO to permit self-supply of operating reserves and file a plan to correct software problems inhibiting self supply by September 1, 2000. However, FERC denied the requests by RG&E and Niagara Mohawk for retroactive rate relief. On June 30, 2000, RG&E filed a request for rehearing seeking, in part, retroactive rate relief for operating reserve overpayments. This request is currently pending with FERC.



As directed by FERC, on September 1, 2000 the NYISO made a comprehensive compliance filing addressing a number of compliance issues, including operating reserves issues. Because the filing did not, in violation of FERC orders, permit self-supply of operating reserves, RG&E filed a protest of the compliance filing. RG&E also protested a new proposal made by the NYISO to pay suppliers of operating reserves prices based on whether the supplier is located in the west, east or on Long Island, while charging purchasers of operating reserves a single, state-wide rate. On November 8, 2000, FERC issued an order extending the existing bid cap of $2.52/MWH (plus opportunity costs) until such time as FERC determines that the non-spinning reserve markets are demonstrated to be workably competitive. FERC again stressed the requirement that the NYISO permit self-supply of operating reserves. FERC suspended the proposal on pricing of operating reserves based on location for the maximum 5 month period. FERC established a technical conference which was held on January 22 and 23, 2001, to deal with market flaws and market performance in the NYISO, including operating reserves issues.

At the present time, RG&E cannot predict what effects, if any, action ultimately taken by FERC on these issues will have on future operations or the financial condition of RGS or RG&E.

Competition and the Company's Prospective Financial Position.

With PSC approval, RG&E has deferred certain costs rather than recognize them on its statement of income 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 and RG&E's Balance Sheet and a discussion and summary of such regulatory assets is presented in Note 3 to Financial Statements.

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.

Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. In a competitive natural gas market, strandable assets would arise where customers migrate away from dependence on RG&E for full service, leaving RG&E with surplus pipeline and storage capacity, as well as natural gas supplies under contract. A discussion of strandable assets is presented in Note 3 to Financial Statements.

As of December 31, 2000, RG&E believed that its regulatory assets are probable of recovery. The Electric Settlement does not impair the opportunity of RG&E to recover its investment in these assets. However, the PSC initiated a proceeding in 1998 to address issues surrounding nuclear generation (see Nine Mile Nuclear Plants). The ultimate determination in this proceeding or any proceeding to consider RG&E's proposed sale of Nine Mile Two as discussed under that heading could have an impact on strandable assets and the recovery of nuclear costs.

Rates and Regulatory Matters

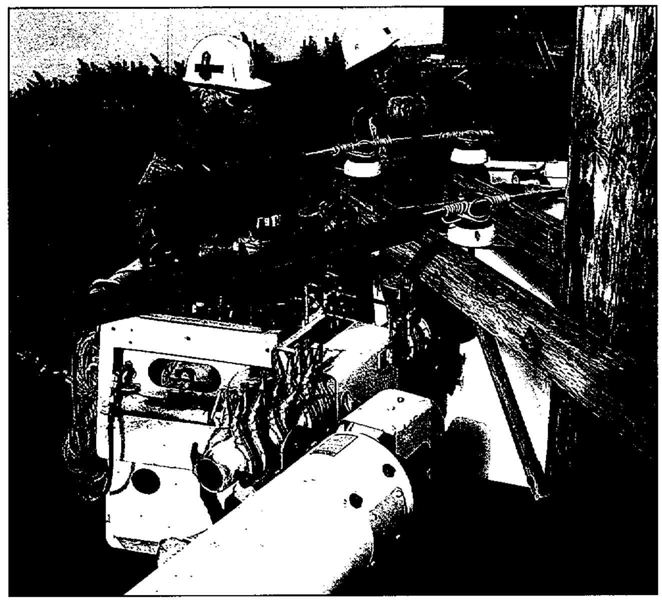
PSC Gas Restructuring Policy Statement.

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 addressed 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 PSC has encouraged settlement negotiations with each gas utility pertaining to the transition to a fully competitive gas market. RG&E, the PSC Staff and other interested parties engaged in settlement discussions in response to the specific requirements of the Gas Policy Statement. In January 2001, RG&E reached agreement with PSC Staff and other parties on a comprehensive rate and restructuring proposal for its natural gas business, as contemplated in the PSC's Gas Policy Statement (See "Gas Retail Access Settlements").

Before trenches are closed an RG&E gas welding inspector must approve the work.

PSC Assignment of Gas Capacity.

Under a March 1996 Order, the PSC permitted RG&E and other gas distribution companies to assign to marketers, as necessary, to serve their customers the pipeline and storage capacity held by RG&E. In its Gas Policy Statement, the PSC ordered that the 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. On March 24, 1999, the PSC issued an Order Concerning Assignment of Capacity for all gas utilities in the State, generally requiring the removal of restrictions on customer migration from utility service to service from marketers. RG&E has complied with the PSC's directives. The Retail Access Capacity Program and the Capacity Incentive Program contained in the Gas Rates and Restructuring Proposal (see "Gas Retail Access Settlements") will, if adopted by the PSC, help to mitigate potential stranded costs resulting from migration of customers to marketers.



Linemen upgrade electric system reliability by installing aluminum ties to secure conductors to insulators.

FERC Gas Market Proposals.

On February 9, 2000, FERC issued Order No. 637, its final rule addressing "Regulation of Short-Term Natural Gas Transportation Services" and "Regulation of Interstate Natural Gas Transportation Services". On June 5, 2000 FERC issued Order No. 637-A providing clarification and additional guidance. On July 26, 2000 FERC issued Order No. 637-B upholding Orders No. 637 and No. 637-A. Order No. 637 as clarified revises FERC's regulations to improve the efficiency of the gas transportation market and to provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity. Specifically, Order No. 637 as clarified:

(1) waives the price ceiling for released capacity of less than one year until September 30, 2002;

(2) permits pipelines to propose peak, off-peak and term differentiated rates, provided that they still satisfy the revenue and cost constraints of traditional rate-making, and excess revenues are split with firm customers;

(3) revises FERC's regulations on scheduling procedures, capacity segmentation and pipeline penalties;

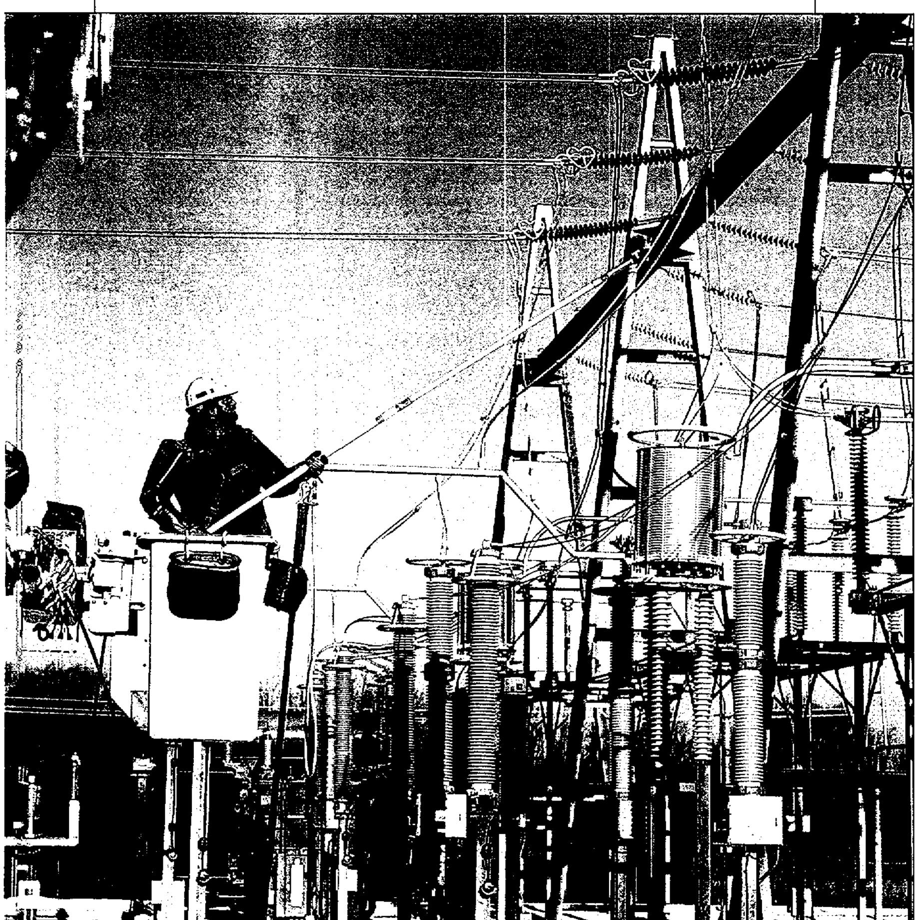
(4) states that the right of first refusal will apply in the future to contracts for 12 consecutive months or more of service at maximum rates; and

(5) amends and supplements reporting requirements

to require interstate pipelines to report additional information on transactions, operationally available capacity, and an expanded index of customers.

Order No. 637 as clarified requires each pipeline to make a compliance filing. All of the pipelines' initial compliance filings were submitted to FERC by August 15, 2000. FERC has established technical and settlement conference procedures for many of the pipelines, including those on which RG&E holds transportation capacity. FERC staff has indicated at the respective pipeline settlement and technical conferences that no action on various pipeline proposals will be taken prior to April 2001, after the heating season has ended.

Neither RGS nor RG&E can predict what effects, if any, FERC's initiatives and the related pipeline tariff changes will have on future operations or the financial condition of RGS or RG&E.



A lineman tests for deenergization with a Salisbury Indicator Tester at Station #122, one of our biggest tie-line hubs. RG&E has spent millions on reliability enhancements; installing lightning arresters which respond in a fraction of a second to take a fault to ground, shut down breakers and protect equipment investment. Wave trap carriers send system integrity communications, simultaneously over power lines, to pinpoint problems accurately to within two utility poles.

FERC Electric Restructuring Order No. 2000.

On December 15, 1999, FERC adopted Order No. 2000 (the Rule), a significant action regarding electric industry restructuring which calls for transmission owners to join regional transmission organizations (RTOs). The RTOs will serve as umbrella organizations that will place all public utility transmission facilities in a region under common control. The Rule required all public utilities that own, operate or control interstate transmission facilities to file by October 15, 2000 (or, for public utilities, like RG&E, already participating in an ISO, by January 15, 2001), a proposal for an RTO, or, alternatively, a description of any efforts made by the utility to participate in an RTO.

On January 16, 2001, the NYISO and all the New York State public utilities made a joint filing with FERC regarding the establishment of an RTO. In the consensus filing, the parties submit that the NYISO meets the general requirements of an RTO, and the NYISO agrees to make certain enhancements of its structure and programs to benefit the markets. Minor modifications are proposed to the governance structure and transmission planning, and the NYISO agrees to coordinate more closely with other RTOs.

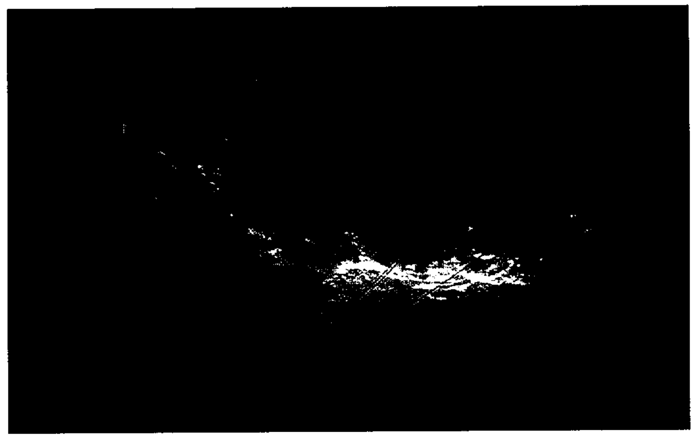
RG&E cannot predict what effect, if any, the ultimate ruling by FERC will have on future operations or on the financial condition of the Company.

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 Electric Settlement, 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 regulated electric sales to customers are made under long-term contracts, primarily to large industrial customers. These contracts represent approximately 48 percent of RG&E's revenues from its commercial and industrial customers.

Liquidity and Capital Resources

During 1998, 1999 and 2000, RGS's and RG&E's cash flow from operations (see Statements of Cash Flows) provided the funds for utility plant construction expenditures, the payment of dividends, the purchase of treasury stock, the retirement of long-term debt and, in 1999, the retirement of short-term debt. In addition, RG&E completed long-term financings in 1998 and 1999. Compared to 1999, cash used for investing activities in 2000 was higher due to increased net additions to utility plant and acquisitions by Griffith during the year. Cash flow from financing activities for 2000 reflect higher proceeds from short-term borrowings, partially offset by the retirement of long-term debt. Capital requirements of the Company during 2001 are anticipated to be satisfied from the combination of internally generated funds, short-term credit arrangements, and possibly some external long-term financing. In addition, completion of the Nine Mile Two sale would also provide additional funds as previously discussed under the heading Nine Mile Nuclear Plants. RG&E may also refinance long-term securities obligations during 2001 depending on prevailing financial market conditions.



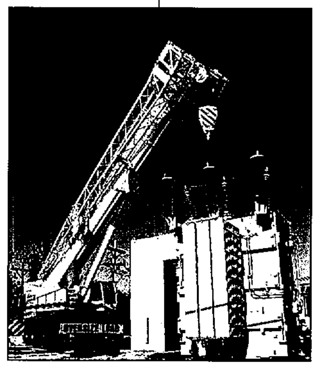
Capital and Other Requirements.

RGS's and RG&E's capital requirements relate primarily to expenditures for energy delivery, including electric transmission and distribution facilities and gas mains and services, as well as for nuclear fuel, electric production, and the repayment of existing debt. RG&E has no plans to install additional baseload generation.

1998 Labor Day Storm. On September 7, 1998, a severe lightning and windstorm struck RG&E's franchise area. The storm damaged RG&E's electrical system at several hundred different locations. Several counties within RG&E's franchise area were declared State and federal disaster areas. RG&E has deferred approximately $9.3 million of costs and carrying charges associated with this storm. Under the Electric Settlement, if incremental costs resulting from a "catastrophic event" exceed $2.5 million, RG&E is entitled to defer the entire amount of such costs for future recovery. RG&E submitted a petition to the PSC for deferral of costs associated with this storm and this petition is currently pending.

Settlement with Co-generator. In May 1998, RG&E 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 Global Settlement Agreement became effective. Under the terms of the Global Settlement Agreement, a Power Purchase Agreement was terminated in consideration of payment by RG&E of $168 million over 16 years, without interest, with an initial payment of $10 million. Also, under the terms of the Global Settlement Agreement, RG&E paid an additional $15 million for the purchase of the Kamine generation facility. In June 1999, the plant began generating electricity (see "Fossil Units Status"). RG&E does not expect the terms of the Global Settlement Agreement to have any material effect on its earnings or the earnings of RGS. Pursuant to the PSC order approving the terms of the Global Settlement Agreement, regulatory assets have been established by RG&E to account for the initial payment, the facility purchase and future payments. RG&E has no other long-term obligations to purchase energy from co-generation facilities.

Capital Requirements – Summary. Capital requirements for the Company over the three-year period 1998 to 2000 and the current estimate of capital requirements through 2003 are summarized in the Capital Requirements table. RG&E's portion of total construction requirements as presented in the Capital Requirements table for 2001, 2002, and 2003 are $161 million, $161 million, and $142 million, respectively.



A new transformer is set into a major substation.

The Company's capital expenditures program is under continuous review and could be revised for many reasons. Also, RG&E may consider, as conditions warrant, the redemption or refinancing of certain outstanding long-term securities.

Financing.

In December 2000, RG&E filed a shelf registration with the Securities and Exchange Commission to issue up to $400 million of long-term debt securities on terms to be determined at the time the securities are sold. This registration statement became effective in January 2001 and allows RG&E financing flexibility regarding the timing of the issuance of debt. Net proceeds from any financings under this shelf registration may be used by RG&E to finance a portion of its capital expenditures, to repay short-term debt or maturing securities, to redeem or purchase outstanding preferred stock or debt securities, or for general corporate purposes.

RG&E generally utilizes its credit agreements and unsecured lines of credit to meet any interim external financing needs prior to issuing long-term securities. For information with respect to RGS's and RG&E's short-term borrowing arrangements and limitations, see Note 10 of the Notes to Financial Statements. As financial market conditions warrant, RG&E may also, from time to time, redeem higher-cost senior securities.

The number of outstanding shares of common stock of RG&E and RGS, as applicable, increased by 23,466 shares in 1998 and 70,913 shares in 2000 as a result of options that were actually exercised under the Company's Performance Stock Option Plan. These were the only shares of common stock issued in 1998 and 2000. Neither RGS nor RG&E issued any additional shares of common stock in 1999.

Redemption of Securities.

In addition to first mortgage bond maturities and mandatory sinking fund obligations of $80 million over the past three years, discretionary redemption of long-term securities totaled $25.5 million in 1998. There were no discretionary redemptions of long-term securities in 1999 or 2000.

Stock Repurchase Plan.

In April 1998, the PSC approved a stock repurchase plan for RG&E providing for the repurchase of common stock having an aggregate market value not to exceed $145 million. RG&E began the repurchase program in

Capital Requirements - RGS

(Millions of Dollars)

Type of Facilities	Actual 1998	Actual 1999	Actual 2000	Projected 2001	Projected 2002	Projected 2003
Electric Property						
Production	$ 16	$ 14	$ 12	$ 17	$ 23	$ 14
Energy Delivery	41	42	63	79	77	69
Subtotal	57	56	75	96	100	83
Nuclear Fuel	14	14	22	7	19	16
Total Electric	71	70	97	103	119	99
Gas Property	21	19	23	31	25	26
Common Property	21	20	23	28	18	19
Total	113	109	143	162	162	144
Carrying Costs						
Allowance for Funds Used During Construction	1	2	2	2	2	2
Total Construction Requirements	114	111	145	164	164	146
Securities Redemptions, Maturities and Sinking Fund Obligations*	66	10	30	–	100	80
Total Capital Requirements	$180	$121	$175	$164	$264	$226

** Excludes prospective refinancings.*

May 1998 and an aggregate of 4,379,300 shares of RG&E and RGS common stock have been repurchased for approximately $117.2 million through December 31, 2000. The average cost per share purchased during 2000 was $23.66.

Environmental Issues.

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. RGS and RG&E have 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.

RGS and RG&E have 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 RGS and RG&E do 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 RGS's and RG&E's environmental matters can be found in Note 12 to Financial Statements.

Risk Management.

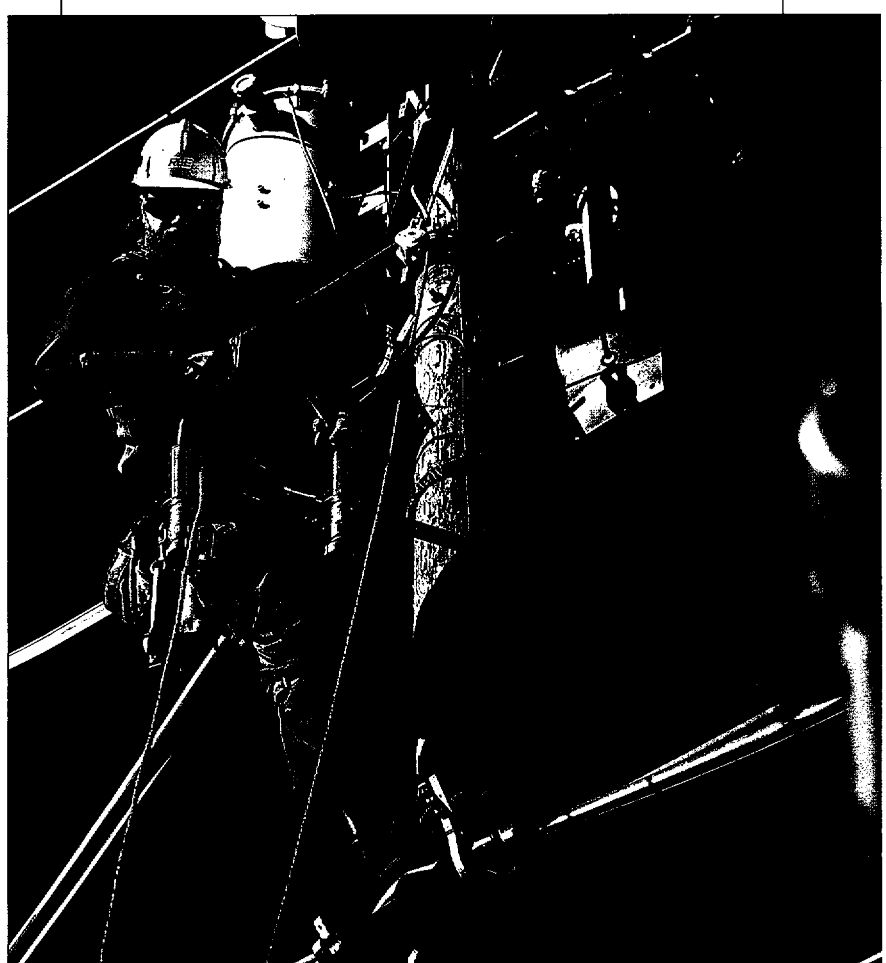
RGS has established and enforces formal internal policies regarding price, credit, and operating risk, which govern the risk practices of all subsidiaries. Recognizing the critical and increasing importance of risk management, RGS established a formal risk management function within the organization and continues to work with consultants and strategic partners to further implement and integrate risk management practices throughout the organization.

The Company faces significant commodity price risk. Commodity price risk relates to market fluctuations in the price of natural gas, electricity, and other petroleum-related products used for resale. Under its Electric Settlement, RG&E's electric rates are capped at specified levels through June 30, 2002. Owned electric generation and long-term supply contracts significantly reduce RG&E's exposure to market fluctuations for procurement of its electric supply.

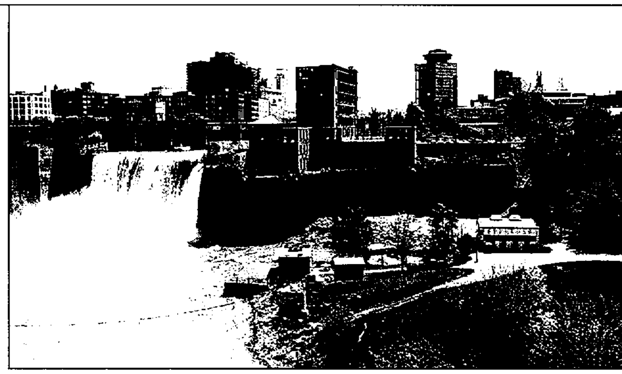
While owned generation provides the Company with a natural hedge against electric price risk, it also subjects the Company to operating risk. Operating risk is managed through a combination of strict operating and maintenance practices and the use of financial instruments. In the event RG&E's generation assets fail to perform as planned, generation insurance and purchased call options reduce the Company's exposure to electric price spikes in the summer months. In addition, RG&E and Energetix rely on various derivative contracts to cover supply positions and commitments, and to hedge energy price exposure. Derivative contracts are entered into solely to optimize resources in conjunction with serving customers. Neither RGS nor any subsidiary enters into speculative contracts for trading purposes.

Year 2000 (Y2K) Computer Operational Information.

On and after January 1, 2000, the Company and RG&E have experienced normal operations of their computer and microprocessor-based devices with no loss or interruption of energy generation or delivery and no operating difficulties of its mission critical internally



developed applications or critical devices. RG&E's two major electric generating plants, Ginna and Russell Station, performed without any difficulties. Likewise, operations at the Nine Mile Two electric power plant proceeded normally and there has been no major impact on gas service. RG&E is not aware of any regional or statewide power systems that failed to perform as the result of Y2K-related problems.



High Falls – a Renaissance for Downtown Rochester and long a source of hydropower for RG&E customers.

RG&E funded its Y2K Project internally and incurred $9.5 million of incremental costs associated with making the necessary modifications identified to applications and devices. Neither RGS nor RG&E has deferred any major corporate information technology projects due to this effort.

Earnings Summary

RGS. RGS reported consolidated earnings of $2.61 per share in 2000 compared to $2.44 in 1999. Higher wholesale electric sales, the recognition of increased non-cash pension income, lower taxes, and the Company's share buyback program positively affected 2000 results. Having a negative effect on earnings in 2000 were electric and gas rate reductions, increased purchased power expenses arising from industry restructuring and generation plant availability, cooler summer weather which mitigated electric air conditioning load sales, and the establishment of reserves in accordance with the Return on Equity Test pursuant to the Electric Settlement.

Linemen change out a pole-mounted transformer.

RGS continues to grow its unregulated business through its subsidiary, Energetix, which provides electric, natural gas, and petroleum-based energy products and services throughout the Upstate New York region. Energetix's unconsolidated operating revenues were $484 million in 2000, of which sales from Griffith and its subsidiaries contributed approximately $377 million. These Griffith revenues are included under "Other Revenues" on RGS's and, where applicable, RG&E's Income Statements and, compared with a year earlier, reflect an increase due to customer growth and increases in fuel oil prices. Energetix's revenues for 2001 are expected to increase over 2000 levels as Energetix expands its customer base and the operations from businesses recently acquired by Griffith are reflected for an entire year; although no assurance may be given that Energetix will achieve a net operating gain in 2001.

RG&E. Earnings for RG&E in 2000 were impacted by the same factors discussed above for RGS except that discussions relating to Energetix and Griffith are not applicable. On August 2, 1999, RGS was formed and RG&E, Energetix and RGS Development then became subsidiaries of RGS. The RG&E Income Statements reflect the consolidated operations of RG&E and its former subsidiaries, Energetix and RGS Development prior to August 2, 1999. Starting August 2, 1999, the RG&E Income Statements reflect only the operating results of RG&E.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses for RGS (regulated and unregulated business) and RG&E (regulated business), comparing 2000 to 1999 and 1999 to 1998. The operating results of the regulated business reflect RG&E's electric and gas sales and services and the operating results of the unregulated business reflect Energetix's operations. Currently, the majority of RGS's operating results reflect the operating results of RG&E and the factors that affect operating results for RG&E are the significant factors that affect comparable operating results for RGS, unless otherwise noted. The Notes to Financial Statements contain additional information.

2000 Compared to 1999

Operating Revenues and Sales.

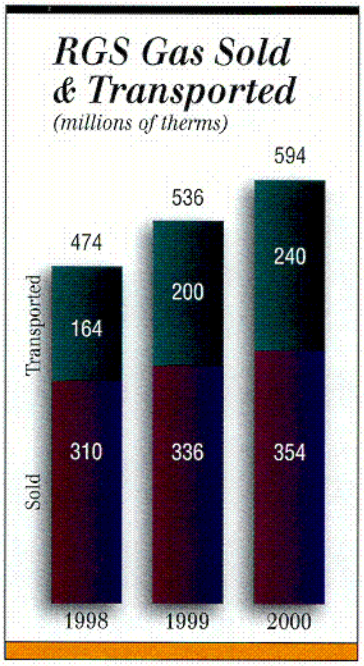
Increased electric revenues for RGS and RG&E reflect higher revenues from the sale of energy to other electric utilities. Revenues from these sales were up $48.2 million due to higher market prices, coupled with an increase in energy kilowatt-hour sales. Fluctuations in revenues from electric sales to 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.

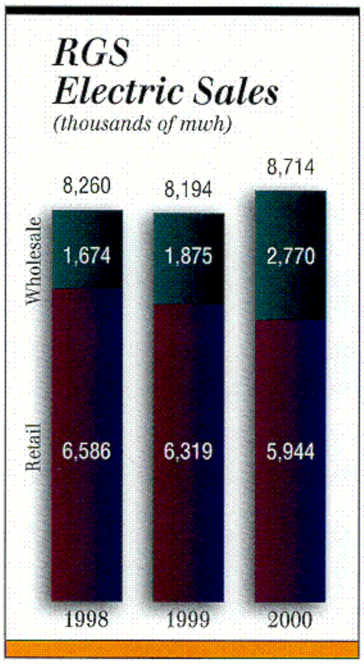
Installing animal guard fencing around electric substations is saving money, animals and reducing power outages.

Partially offsetting the favorable results of energy sales to other utilities was a drop of $25.2 million in 2000 from a combination of electric revenues from regulated retail electric sales and electric sales to energy marketers reflecting a June 1999 unbilled electric revenue adjustment of $7.1 million (see heading "1999 Compared to 1998"), unfavorable weather conditions for air conditioning load during the summer of 2000 which was nearly 40% colder than a year earlier based on cooling degree days, and electric base rate reductions effective July 1, 1999 and July 1, 2000 (see "Energy Choice").

A drop in commercial and industrial regulated electric unit sales reflects, in part, the opening of the electric market under the terms of the Electric Settlement. RG&E, however, sells electric energy, as well as distribution services, to qualified energy marketers in its franchise territory which has the effect of increasing wholesale sales to energy marketers. Included in RG&E's electric operating revenues for 2000 are $99.5 million of revenues from electric sales to energy marketers and $73.6 million of revenues from wholesale sales to other utilities.

Regulated gas margins (revenues less cost of purchased gas) were down about $1.3 million in 2000. Gas revenues in 2000 reflect a $1.4 million rate reduction pursuant to the terms of the Gas Rates and Restructuring Proposal (see "Competition"). In addition, the favorable effect of increased gas spaceheating sales resulting, in part, from 5.6 percent cooler weather (based on heating degree days) for the year was offset by the effects of a June 1999 unbilled gas revenue adjustment of $6.1 million (see heading "1999 Compared to 1998").





Gas revenues from therms of gas sold and transported for the regulated business were $31.3 million in 2000 compared with $21.2 million in 1999. The transportation of gas for customers who are able to purchase natural gas from sources other than RG&E is an important component of RG&E's marketing mix. In 2000, RG&E's small customer aggregate transportation market appeared as a significant addition to RG&E's marketing mix. Company facilities are used to distribute this gas, which in total amounted to 24.0 million dekatherms in 2000 and 20.0 million dekatherms in 1999. These purchases by eligible customers have caused decreases in RG&E'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 gas and transporting it to RG&E's city gate, are the same as the rates charged RG&E's retail gas service customers. Moreover, under the current regulatory environment, RG&E does not earn a return on the gas commodity it acquires for distribution. Gas supplies transported in this manner are not included in RG&E's retail therm sales, depressing reported gas sales to such retail customers.

Seventy-eight percent of Energetix's total operating revenues in 2000 were from the sale of fuel oil, propane and gasoline by Griffith (see discussion under "Earnings Summary"). For heating oil and propane, Griffith experiences seasonal fluctuations due to the dependence on

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The latest circuit breaker technology is now installed at RG&E's largest substation.

spaceheating sales during the heating season. In addition, gasoline sales reflect seasonal fluctuations due to increased consumer driving during the warmer months. Moreover, operations from businesses acquired by Griffith have been reflected in Griffith's operations since their acquisition (see "Unregulated Subsidiaries").

Operating Expenses.

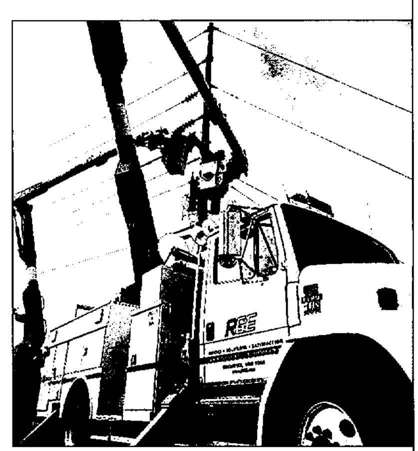
Higher regulated electric fuel expenses reflect increased purchased electricity costs driven by an increase in the cost per unit purchased, hedging activities, the effect of decreased generation availability from the Nine Mile Two nuclear plant primarily due to a scheduled refueling in 2000, and the absence of generation from the Oswego Generating Facility which was closed in August 1999. The cost of purchased power may fluctuate depending on the availability of electric generation from RG&E's facilities, the wholesale energy market and the total availability of energy, and the availability of transmission facilities. Since July 1996, Common Stock shareholders have assumed 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 RG&E's production cost.

The cost of gas purchased for resale increased in 2000 driven mainly by the rise in the commodity cost of gas. RG&E's regulated gas tariffs include a monthly gas adjustment clause which allows RG&E to recover pipeline and storage capacity costs and the commodity cost of gas purchased for its customers. On an annual basis, RG&E reconciles the costs collected through the monthly gas adjustment clause and the actual gas costs for the prior twelve months. As stated above, RG&E does not earn a return on the gas capacity and commodity it acquires for distribution to its customers.

Unregulated fuel expenses on both RGS's and RG&E's Income Statements reflect mainly the cost of purchased fuel for Griffith's operations.

The increase in non-fuel operating expenses in 2000 for RGS and RG&E includes an increase of $18.4 million for electric transmission and wheeling charges related to the implementation of the NYISO (see discussion under "New York Independent System Operator"), increased regulatory amortization associated with the closing of Oswego Station ($5.2 million) and an accrual for site remediation costs ($3.9 million). These increases were offset by an $8.0 million drop in RG&E welfare expense associated with the performance of pension assets (see Note 5 to Financial Statements), lower expenses in 2000 due to an increase in 1999 ($7.1 million) of the RG&E reserve for uncollectible accounts, the absence of Y2K expenses ($4.8 million), a one-time refund of NYISO start-up costs ($4.5 million), and the reversal of a $3.0 million liability established in 1999 for Nine Mile Two inventory losses due to the currently anticipated sale of Nine Mile Two ($6.0 million).

The financial results for 2000 resulted in the establishment of reserves totaling $18.3 million in accordance with the terms of the Electric Settlement. These reserves are comprised of a $16.3 million reserve based on the provisions of the Return on Equity Test (as previously discussed under the heading Electric Settlement) and a $2.0 million reserve for estimated property tax savings. These reserves are reflected in non-fuel operating expenses.



The variance in unregulated non-fuel operating expenses between 2000 and 1999 reflects primarily payroll, Griffith's fleet expenses, and incremental operating expenses from the companies acquired by Griffith during 2000.

Depreciation expense for both RGS and RG&E reflects a decrease in regulated depreciation mainly associated with the retirement of RG&E generating plant facilities in 1999 (see discussion under "Fossil Units Status"). Depreciation and amortization expense for unregulated operations increased $0.9 million in 2000 to $4.1 million due primarily to acquisitions.

Local, State and other taxes for RGS and RG&E declined mainly as a result of lower regulated revenues, a lower gross receipts tax, elimination of the excess dividends tax effective January 1, 2000, and lower property taxes resulting from the retirement of RG&E generating facilities in 1999 as mentioned in the previous paragraph. Partially offsetting the reduction in these taxes was the imposition of new State income taxes that totaled $10.0 million in 2000 (see discussion under Note 1 to Financial Statements, "New York State Tax Changes").

The difference in income tax expense for RGS and RG&E is attributable mainly to differences in pretax earnings, a reclassification of the State gross receipts tax to State income tax and a true-up of both federal and State income tax for a new State income tax effective January 1, 2000 (see discussion under Note 1 to Financial Statements, "New York State Tax Changes").

Other Statement of Income Items.

The change in non-operating income taxes for both RGS and RG&E results from variances in non-operating earnings before income taxes and a true-up of both federal and State income tax for the new State income tax effective January 1, 2000 as discussed in the previous paragraph.

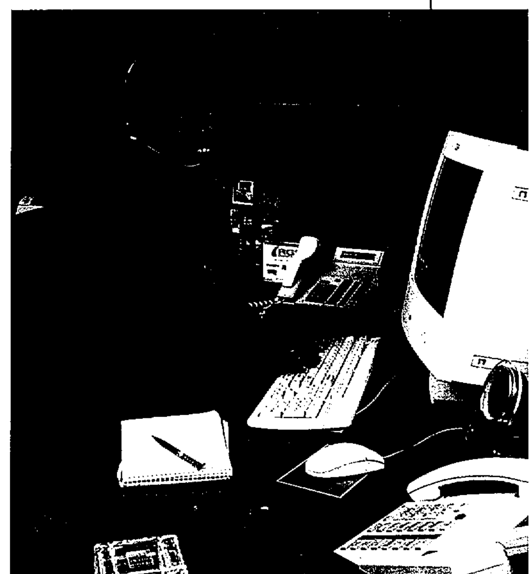
The change between 2000 and 1999 in RGS's and RG&E's Other Income and Deductions, Other-net reflects reduced expenses in 2000 associated with RG&E management performance awards ($4.8 million). Compared with a year earlier, the change in 2000 also reflects the effect of income in 1999 resulting primarily from the gain on the disposal of property ($2.8 million).

The increase in interest expense for both RGS and RG&E reflects the interest on $100 million of first mortgage bonds issued in October 1999. Higher other interest expenses are due mainly to interest costs associated with RG&E's annual gas supply reconciliation adjustments and interest on security deposits provided by certain energy marketers. Partially offsetting this increase in interest expense was a reduction of RG&E interest expense on short-term debt.

1999 Compared to 1998

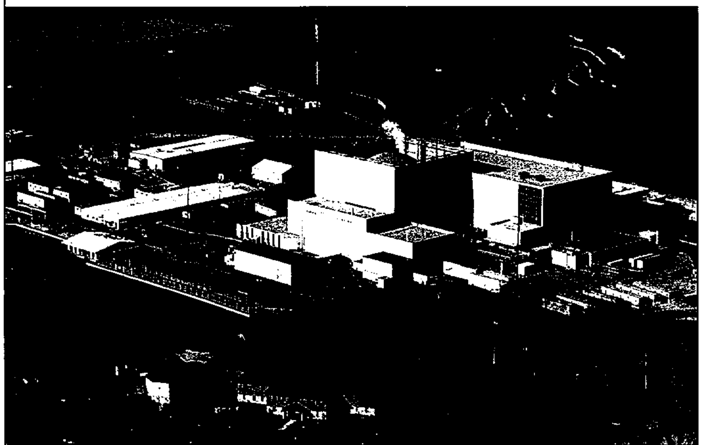
Operating Revenues and Sales.

Increased electric revenues in 1999 for RGS and RG&E reflect increased demand for air conditioning usage resulting from summer weather that was 25% warmer than during 1998 (on a cooling degree day basis). This increase in revenues was partially offset by a base rate reduction pursuant to the terms of the Electric Settlement and lower regulated electric sales due largely to RG&E's reduced capacity to sell power to other electric utilities because of a refueling and in-service inspection outage at the Ginna Plant and an unscheduled 30-day outage at Nine Mile Two. Regulated sales and revenues for 1999 compared to 1998 also reflect a one-time adjustment to reflect a change in the estimating process for unbilled sales and revenues. This adjustment increased regulated electric revenues by $7.1 million and increased regulated gas revenues by $6.1 million. Regulated electric sales increased by 74,000 megawatt-hours and regulated gas sales were higher by 7,610,000 therms as a result of this one-time adjustment. Included in RGS's electric operating revenues for 1999 are $65.2 million of revenues from electric sales to energy marketers and $25.3 million of revenues from wholesale sales to other utilities. Revenues in 1999 from energy marketers were up $50.2 million compared with 1998 reflecting the opening of the electric marketplace and increased sales of electricity and distribution services. Revenues from the sales of electric energy to other utilities dropped $3.7 million from 1998 due mainly to the unavailability of RG&E's generating plants as discussed above, partially offset by an increase in the average revenue per unit sold.



An RG&E investor relations service representative responds to a customer call utilizing state-of-the-art data systems.

Regulated gas margins (revenues less cost of purchased gas) were up over $12 million reflecting 11 percent cooler weather (based on heating degree days) for the year and the change in unbilled sales methodology discussed above. Therms of gas sold and transported for the regulated business were up 10.7 percent in 1999.



RG&E's Ginna Nuclear Power Plant, which first produced power in 1969, is not only the longest running nuclear plant in America, but also remains at the top of plant performance records.

Approximately 78 percent of Energetix's total operating revenues in 1999 were from the sale of fuel oil, propane and gasoline by Griffith. Unregulated sales reflect Griffith's operations since its acquisition by Energetix on August 2,1998 and the migration of electric and gas customers from the regulated to the unregulated business.

Operating Expenses.

Higher regulated electric fuel expenses reflect increased purchased electricity costs that were driven by a combination of lower generation from the Ginna nuclear plant, hydro plants, and the closing of Beebee Station on April 30, 1999, coupled with an increase in the cost per unit purchased. Fuel expense for electric generation was down in 1999 reflecting lower generation from RG&E's facilities. Despite an increase in retail regulated gas therm sales, gas purchased for resale expense declined in 1999 reflecting a lower average cost per unit due, in part, to a reduction in pipeline costs.

An RG&E technician calibrates a preventive relay system. Relays sensing a fault, must operate within strict current tolerances and response time parameters to automatically shut down the circuit and reroute loads to ensure safety and reliability.

Other fuel expense on both RGS's and RG&E's Income Statements reflects mainly the cost of purchased fuel for Griffith's operations since its acquisition by Energetix.

The decrease in non-fuel operating expenses for RGS and RG&E includes a $4.8 million drop in RG&E welfare expense from 1998 due mainly to the performance of pension assets and a change in the discount rate used to value the aggregate pension liability (see Note 5 to Financial Statements), elimination in the first quarter of 1999 of property insurance and storm reserves no longer required totaling $2.1 million, lower non-fuel net expenses of $1.5 million associated with Ginna Plant refueling outages, a decrease of $2.8 million relating to the completion in 1998 of the amortization of costs of RG&E's billing system, insurance dividends of $1.8 million, and lower employee performance incentive program costs of $1.1 million. Offsetting these declines was a June 1999 increase in the allowance for uncollectible accounts of approximately $7.1 million to better match RG&E's actual collection history, the establishment in the fourth quarter of 1999 of a $3.0 million liability for anticipated Nine Mile Two inventory losses due to a change in the expected ownership of that facility, and increased Y2K costs of $6.0 million.

The variance in unregulated non-fuel operating expenses reflects primarily an increase in payroll expenses, other operating expenses for Griffith, and general and administrative expenses. The increase in these expenses reflects twelve months of Griffith's operations in 1999 compared with only five months of Griffith's operations in 1998 following its acquisition in August 1998.

Depreciation expense for both RGS and RG&E in 1999 includes an incremental one-time charge in the second quarter of approximately $2.1 million associated with the closing of Beebee Station in April 1999. Depreciation and amortization expense for unregulated operations in 1999 was $3.2 million, up $2.1 million from 1998, due to the acquisition of Griffith.

Local, State and other taxes for RGS and RG&E declined in 1999 compared to 1998 reflecting a New York State use tax audit refund, lower tax rates for State and local revenue taxes, and lower assessments for property taxes. These results were partially offset by higher unbilled revenue taxes resulting from an increase in unbilled revenues. For unregulated operations, local, State and other taxes in 1999 increased $2.9 million to $4.0 million compared to 1998 due to the acquisition of Griffith.

The difference in federal income tax expense for RGS and RG&E reflects pre-tax earnings and, regarding RG&E, the settlement of RG&E audits in 1998 and a

Crewmen checking LTC (Load Tap Changer) control circuits in the transformer.

$4.8 million increase in the 1999 tax reserve related to disputed tax issues.

Other Statement of Income Items.

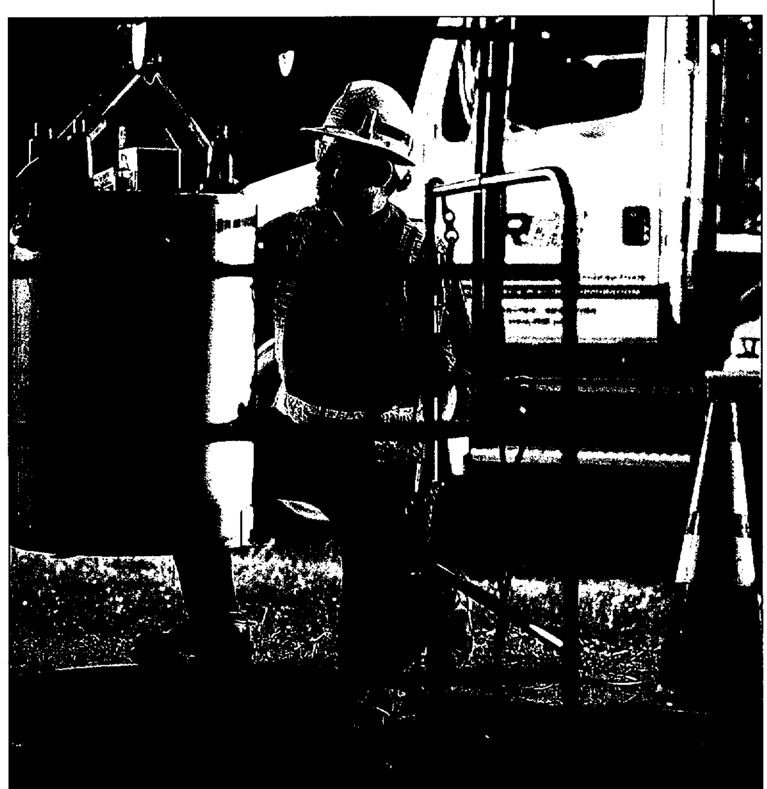
The change in non-operating federal income taxes for both RGS and RG&E results from variances in non-operating earnings before federal income taxes.

The change between 1999 and 1998 in RGS's and RG&E's Other Income and Deductions, Other-net reflects mainly the recognition of income ($17.4 million) in 1998 due to the elimination of certain pension and other post-employment benefit deferred credits and Nine Mile Two operating and maintenance expenses in accordance with the Electric Settlement. This variance in Other Income and Deductions, Other-net was partially offset by non-cash carrying charges of $8.6 million related to deferral of Kamine (Allegany Station) facility costs in 1999 for the regulated business. These carrying charges, which are primarily associated with the deferred recovery of costs associated with the Kamine settlement (see following paragraph), were allowed under the Electric Settlement and the Kamine settlement. In addition, expenses associated with RG&E management performance awards decreased $4.4 million in 1999 compared with 1998.

The increase in RGS's interest charges reflects mainly an increase in long-term debt outstanding, resulting mainly from the Kamine settlement, the acquisition of Griffith by Energetix, and the issuance of $50 million of long term debt by RG&E in December 1998. The increase in RG&E's interest charges was impacted by the same factors except the debt incurred for the Griffith acquisition. Interest expense in 1999 for both RGS and RG&E also reflects the interest on $100 million of first mortgage bonds issued in October 1999.

Dividend Policy

The ability of RGS to pay common stock dividends is governed by the ability of RGS's subsidiaries to pay dividends to RGS. Because RG&E is by far the largest of RGS's subsidiaries, it is expected that for the foreseeable future the funds required by RGS to enable it to pay dividends will be derived predominantly from the dividends paid to RGS by RG&E. In the future, dividends from subsidiaries other than RG&E may also contribute to RGS's ability to pay dividends. RG&E's ability to make dividend payments to RGS will depend upon the availability of retained earnings and the needs of its utility business. RG&E's Certificate of Incorporation provides for the payment of dividends on its common stock out of the surplus net profits (retained earnings) of RG&E. In addition, pursuant to the PSC order approving the formation of RGS, RG&E may pay dividends to RGS of no more than 100% of RG&E's net income calculated on a two-year rolling basis. The calculation of net income for this purpose excludes non-cash charges to income resulting from accounting changes or certain PSC required charges as well as charges that may arise from significant unanticipated events. This condition does not apply to dividends that would be used to fund the remaining portion of RG&E's $100 million authorization for unregulated operations (about $13 million at December 31, 2000).



Crewman lowering a submersible stainless steel vacuum switch into a manhole for an underground installation.

Financial Reports Table of Contents

Report of Independent Accountants

PRICEWATERHOUSECOOPERS

1100 Bausch & Lomb Place
Rochester, New York 14604-2705
January 31, 2001

To the Shareholders and Board of Directors of
RGS Energy Group, Inc. and 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 RGS Energy Group, Inc. and its subsidiaries ("RGS") at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 and the accompanying balance sheets and the related statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation ("RG&E") at December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the RGS and RG&E 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 auditing standards generally accepted in the United States of America, 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 our opinion.

PricewaterhouseCoopers LLP

RGS Energy Group, Inc.
Consolidated Statement of Income

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
OPERATING REVENUES			
Electric	**$ 731,006**	$ 702,751	$ 687,622
Gas	**340,014**	284,476	274,657
Other	**377,099**	220,310	71,212
Total Operating Revenues	**1,448,119**	1,207,537	1,033,491
OPERATING EXPENSES			
Fuel Expenses			
Fuel for electric generation	**48,851**	49,297	53,954
Purchased electricity	**85,858**	54,337	27,024
Gas purchased for resale	**208,588**	151,458	155,497
Unregulated fuel expenses	**340,306**	189,465	59,490
Total Fuel Expenses	**683,603**	444,557	295,965
Operating Revenues Less Fuel Expenses	**764,516**	762,980	737,526
Other Operating Expenses			
Operations and maintenance excluding fuel expenses	**313,721**	297,890	301,625
Unregulated operating and maintenance expenses excluding fuel	**31,125**	26,464	13,524
Depreciation and amortization	**116,184**	118,695	116,102
Taxes–local, state and other	**94,576**	114,639	117,973
Income tax	**59,832**	64,374	60,236
Total Other Operating Expenses	**615,438**	622,062	609,460
Operating Income	**149,078**	140,918	128,066
OTHER (INCOME) AND DEDUCTIONS			
Allowance for other funds used during construction	**(825)**	(657)	(408)
Income tax	**1,145**	(1,255)	1,665
Other, net	**(9,521)**	(8,178)	(13,370)
Total Other (Income) and Deductions	**(9,201)**	(10,090)	(12,113)
INTEREST CHARGES			
Long term debt	**58,044**	53,681	43,306
Other, net	**5,995**	4,798	3,388
Allowance for borrowed funds used during construction	**(1,319)**	(1,051)	(653)
Total Interest Charges	**62,720**	57,428	46,041
Net Income	**95,559**	93,580	94,138
Preferred Stock Dividend Requirements	**3,700**	4,083	4,842
Net Income Applicable to Common Stock	**$ 91,859**	$ 89,497	$ 89,296
Earnings per Common Share–Basic	**$2.61**	$2.44	$2.32
Earnings per Common Share–Diluted	**$2.60**	$2.44	$2.31

Consolidated Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
Balance at Beginning of Period	**$153,186**	$129,484	$109,313
Add			
Net Income Applicable to Common Stock	**91,859**	89,497	89,296
Total	**245,045**	218,981	198,609
Deduct			
Dividends declared on capital stock			
Common Stock	**62,989**	65,594	68,927
Other Adjustments	**510**	201	198
Total	**63,499**	65,795	69,125
Balance at End of Period	**$181,546**	$153,186	$129,484
Cash Dividends Declared per Common Share	**$1.80**	$1.80	$1.80

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

RGS Energy Group, Inc.
Consolidated Balance Sheet

(Thousands of Dollars) At December 31,	2000	1999
ASSETS		
Utility Plant		
Electric	**$2,467,289**	$2,399,532
Gas	**471,051**	453,634
Common	**164,872**	130,118
Nuclear	**292,588**	270,447
	3,395,800	3,253,731
Less: Accumulated depreciation	**1,750,493**	1,636,955
Nuclear fuel amortization	**254,435**	239,243
	1,390,872	1,377,533
Construction work in progress	**111,486**	95,862
Net Utility Plant	**1,502,358**	1,473,395
Current Assets		
Cash and cash equivalents	**16,258**	8,288
Accounts receivable, net of allowance for doubtful accounts: 2000–$34,550; 1999–$34,026	**136,374**	90,239
Unbilled revenue receivable	**71,120**	58,005
Fuels	**46,868**	28,704
Materials and supplies	**8,187**	9,502
Prepayments	**26,268**	24,576
Other current assets	**2,292**	523
Total Current Assets	**307,367**	219,837
Intangible Assets		
Goodwill, net	**27,971**	13,894
Other intangible assets, net	**22,614**	7,338
Total Intangible Assets	**50,585**	21,232
Deferred Debits and Other Assets		
Nuclear generating plant decommissioning fund	**244,514**	220,815
Nine Mile Two deferred costs	**27,155**	28,206
Unamortized debt expense	**16,602**	17,984
Other deferred debits	**4,674**	13,137
Regulatory assets	**411,212**	466,231
Other assets	**1,331**	2,037
Total Deferred Debits and Other Assets	**705,488**	748,410
Total Assets	**$2,565,798**	$2,462,874

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

(Thousands of Dollars) At December 31,	2000	1999
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt–mortgage bonds	**$ 580,132**	$ 580,070
–promissory notes	**243,728**	235,395
Preferred stock redeemable at option of RG&E	**47,000**	47,000
Preferred stock subject to mandatory redemption	**25,000**	25,000
Common shareholders' equity		
Common stock		
Authorized 100,000,000 shares; 38,956,726 shares issued at December 31, 2000 and 38,885,813 shares issued at December 31, 1999	**702,807**	700,268
Retained earnings	**181,546**	153,186
	884,353	853,454
Less: Treasury stock at cost (4,379,300 shares at December 31, 2000 and 2,942,600 shares at December 31, 1999)	**117,238**	83,252
Total Common Shareholders' Equity	**767,115**	770,202
Total Capitalization	**1,662,975**	1,657,667
Long Term Liabilities		
Nuclear waste disposal	**97,291**	91,743
Uranium enrichment decommissioning	**9,649**	10,911
Site remediation	**24,420**	23,698
	131,360	126,352
Current Liabilities		
Long term debt due within one year	**12,095**	37,643
Short term debt	**122,400**	10,500
Accounts payable	**108,618**	54,221
Dividends payable	**16,515**	17,078
Equal payment plan	**—**	10,529
Other	**57,491**	39,385
Total Current Liabilities	**317,119**	169,356
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	**277,787**	318,694
Pension costs accrued	**26,547**	48,628
Kamine deferred credit	**51,920**	58,738
Post employment benefits	**54,505**	48,653
Other	**43,585**	34,786
Total Deferred Credits and Other Liabilities	**454,344**	509,499
Commitments and Other Matters *(see Note 12)*	**—**	—
Total Capitalization and Liabilities	**$2,565,798**	$2,462,874

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

RGS Energy Group, Inc.
Consolidated Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31,	2000	1999*	1998*
CASH FLOW FROM OPERATING ACTIVITIES			
Net Income	**$ 95,559**	$ 93,580	$ 94,138
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation & amortization	**132,410**	135,094	135,289
Deferred recoverable fuel costs	**10,873**	1,401	(3,565)
Income taxes deferred	**(14,002)**	9,901	(9,141)
Allowance for funds used during construction	**(2,144)**	(1,708)	(1,061)
Power contract termination costs	**—**	—	(10,000)
Unbilled revenue	**(13,115)**	(20,083)	10,516
Post employment benefit/pension costs	**10,900**	4,100	(2,700)
Provision for doubtful accounts	**152**	7,472	(372)
Changes in certain current assets and liabilities; net of assets acquired and liabilities assumed in acquisitions:			
Accounts receivable	**(37,756)**	(8,420)	27,549
Materials, supplies and fuels	**(12,903)**	4,818	141
Taxes accrued	**(4,711)**	4,095	(1,448)
Accounts payable	**52,615**	1,767	(7,031)
Other current assets and liabilities, net	**8,721**	1,516	1,327
Other, net	**1,070**	(13,742)	(8,029)
Total Operating	**227,669**	219,791	225,613
CASH FLOW FROM INVESTING ACTIVITIES			
Net additions to utility plant	**(142,496)**	(108,339)	(129,286)
Nuclear generating plant decommissioning fund	**(20,736)**	(20,736)	(20,827)
Acquisitions, net of cash	**(48,889)**	(3,152)	(30,977)
Proceeds from sale of Oswego #6	**—**	10,920	—
Electric transmission contract termination costs	**—**	(26,935)	—
Other, net	**(289)**	(147)	484
Total Investing	**(212,410)**	(148,389)	(180,606)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from:			
Sale/Issuance of common stock	**1,772**	—	586
Issuance of long term debt and promissory notes	**17,540**	103,509	99,422
Short term borrowings, net	**111,900**	(46,500)	30,500
Retirement of long term debt	**(30,000)**	(3,104)	(55,500)
Retirement of preferred stock	**—**	(10,000)	(10,000)
Repayment of promissory notes	**(7,290)**	(5,958)	(7,790)
Dividends paid on preferred stock	**(3,700)**	(4,274)	(5,031)
Dividends paid on common stock	**(63,552)**	(66,262)	(69,592)
Payment for treasury stock	**(33,986)**	(36,819)	(46,433)
Other, net	**27**	(229)	(51)
Total Financing	**(7,289)**	(69,637)	(63,889)
Increase (Decrease) in cash and cash equivalents	**$ 7,970**	$ 1,765	$ (18,882)
Cash and cash equivalents at beginning of year	**$ 8,288**	$ 6,523	$ 25,405
Cash and cash equivalents at end of year	**$ 16,258**	$ 8,288	$ 6,523

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
CASH PAID DURING THE PERIOD			
Interest paid (net of capitalized amount)	**$59,060**	$54,059	$43,793
Income taxes paid	**$47,038**	$58,750	$75,600
TRANSFER FROM UTILITY PLANT TO REGULATORY ASSET, NET	**$ —**	$54,255	$ —

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

Rochester Gas and Electric Corporation
Statement of Income

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
OPERATING REVENUES			
Electric	**$ 721,737**	$ 700,194	$ 687,622
Gas	**322,412**	281,555	274,657
Other	**—**	108,699	71,212
Total Operating Revenues	**1,044,149**	1,090,448	1,033,491
OPERATING EXPENSES			
Fuel Expenses			
Fuel for electric generation	**48,851**	49,297	53,954
Purchased electricity	**80,938**	53,046	27,024
Gas purchased for resale	**192,038**	148,983	155,497
Unregulated fuel expenses	**—**	91,505	59,490
Total Fuel Expenses	**321,827**	342,831	295,965
Operating Revenues Less Fuel Expenses	**722,322**	747,617	737,526
Other Operating Expenses			
Operations and maintenance excluding fuel expenses	**313,721**	297,890	301,625
Unregulated operating and maintenance expenses excluding fuel	**—**	14,236	13,524
Depreciation and amortization	**112,110**	117,289	116,102
Taxes–local, state and other	**90,090**	112,613	117,973
Income tax	**59,451**	64,454	60,236
Total Other Operating Expenses	**575,372**	606,482	609,460
Operating Income	**146,950**	141,135	128,066
OTHER (INCOME) AND DEDUCTIONS			
Allowance for other funds used during construction	**(825)**	(657)	(408)
Income tax	**221**	(1,144)	1,665
Other, net	**(8,897)**	(8,111)	(13,370)
Total Other (Income) and Deductions	**(9,501)**	(9,912)	(12,113)
INTEREST CHARGES			
Long term debt	**56,673**	53,067	43,306
Other, net	**5,568**	4,543	3,388
Allowance for borrowed funds used during construction	**(1,319)**	(1,051)	(653)
Total Interest Charges	**60,922**	56,559	46,041
Net Income	**95,529**	94,488	94,138
Dividends on Preferred Stock	**3,700**	4,083	4,842
Net Income Applicable to Common Stock	**$ 91,829**	$ 90,405	$ 89,296

Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
Balance at Beginning of Period	**$137,854**	$129,484	$109,313
Add			
Net Income	**95,529**	94,488	94,138
Total	**233,383**	223,972	203,451
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock–at required rates	**3,700**	4,083	4,842
Common Stock	**62,989**	65,594	68,927
Adjustment Associated with RGS Energy Group Formation	**—**	16,243	—
Other Adjustments	**510**	198	198
Total	**67,199**	86,118	73,967
Balance at End of Period	**$166,184**	$137,854	$129,484

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

Rochester Gas and Electric Corporation
Balance Sheet

(Thousands of Dollars) At December 31,	2000	1999
ASSETS		
Utility Plant		
Electric	**$2,467,289**	$2,399,532
Gas	**471,051**	453,634
Common	**117,473**	107,469
Nuclear	**292,588**	270,447
	3,348,401	3,231,082
Less: Accumulated depreciation	**1,735,752**	1,634,334
Nuclear fuel amortization	**254,435**	239,243
	1,358,214	1,357,505
Construction work in progress	**111,486**	95,862
Net Utility Plant	**1,469,700**	1,453,367
Current Assets		
Cash and cash equivalents	**4,851**	6,443
Accounts receivable, net of allowance for doubtful accounts: 2000–$33,482; 1999–$33,365	**93,699**	70,388
Affiliate receivable	**50,989**	13,197
Unbilled revenue receivable	**61,838**	55,661
Fuels	**33,896**	23,876
Materials and supplies	**8,187**	9,502
Prepayments	**23,782**	23,439
Total Current Assets	**277,242**	202,506
Deferred Debits and Other Assets		
Nuclear generating plant decommissioning fund	**244,514**	220,815
Nine Mile Two deferred costs	**27,155**	28,206
Unamortized debt expense	**16,602**	17,984
Other deferred debits	**4,674**	13,760
Regulatory assets	**411,212**	466,231
Total Deferred Debits and Other Assets	**704,157**	746,996
Total Assets	**$2,451,099**	$2,402,869

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

(Thousands of Dollars) At December 31,	2000	1999
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt–mortgage bonds	**$ 580,132**	$ 580,070
–promissory notes	**211,703**	215,930
Preferred stock redeemable at option of RG&E	**47,000**	47,000
Preferred stock subject to mandatory redemption	**25,000**	25,000
Common shareholder's equity		
Authorized 50,000,000 shares; 38,885,813 shares issued at December 31, 2000 and at December 31, 1999	**700,318**	700,268
Retained earnings	**166,184**	137,854
	866,502	838,122
Less: Treasury stock at cost (4,379,300 shares at December 31, 2000 and 2,942,600 shares at December 31, 1999)	**117,238**	83,252
Total Common Shareholder's Equity	**749,264**	754,870
Total Capitalization	**1,613,099**	1,622,870
Long Term Liabilities		
Nuclear waste disposal	**97,291**	91,743
Uranium enrichment decommissioning	**9,649**	10,911
Site remediation	**22,356**	22,357
	129,296	125,011
Current Liabilities		
Long term debt due within one year	**4,227**	33,781
Short term debt	**98,000**	—
Accounts payable	**79,356**	42,263
Affiliate payable	**18,451**	12,961
Dividends payable	**16,515**	17,078
Equal payment plan	**—**	10,529
Other	**41,664**	33,243
Total Current Liabilities	**258,213**	149,855
Deferred Credits and Other Liabilities *(see Note 12)*		
Accumulated deferred income taxes	**274,299**	314,683
Pension costs accrued	**26,548**	48,628
Kamine deferred credit	**51,920**	58,738
Post employment benefits	**54,505**	48,653
Other	**43,219**	34,431
Total Deferred Credits and Other Liabilities	**450,491**	505,133
Commitments and Other Matters *(see Note 12)*	**—**	—
Total Capitalization and Liabilities	**$2,451,099**	$2,402,869

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

Rochester Gas and Electric Corporation
Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31,	2000	1999*	1998*
CASH FLOW FROM OPERATING ACTIVITIES			
Net Income	**$ 95,529**	$ 94,488	$ 94,138
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation & amortization	**128,629**	131,903	135,289
Deferred recoverable fuel costs	**10,873**	1,401	(3,565)
Income taxes deferred	**(12,820)**	5,889	(9,141)
Allowance for funds used during construction	**(2,144)**	(1,708)	(1,061)
Power contract termination costs	**—**	—	(10,000)
Unbilled revenue	**(6,177)**	(17,739)	10,516
Post employment benefit/pension costs	**10,900**	4,100	(2,700)
Provision for doubtful accounts	**117**	7,066	(372)
Changes in certain current assets and liabilities:			
Accounts receivable	**(61,220)**	(10,248)	27,549
Materials, supplies and fuels	**(8,705)**	7,164	141
Taxes accrued	**(5,333)**	2,822	(1,448)
Accounts payable	**42,602**	(3,298)	(7,031)
Other current assets and liabilities, net	**2,144**	663	1,327
Other, net	**970**	(11,876)	(8,029)
Total Operating	**195,365**	210,627	225,613
CASH FLOW FROM INVESTING ACTIVITIES			
Net additions to utility plant	**(140,084)**	(106,359)	(129,286)
Nuclear generating plant decommissioning fund	**(20,736)**	(20,736)	(20,827)
Acquisition, net of cash	**—**	—	(30,977)
Proceeds from sale of Oswego #6	**—**	10,920	—
Electric transmission contract termination costs	**—**	(26,935)	—
Other, net	**769**	467	484
Total Investing	**(160,051)**	(142,643)	(180,606)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from:			
Sale/Issuance of common stock	**—**	—	586
Issuance of long term debt	**—**	100,000	99,422
Short term borrowings, net	**98,000**	(50,500)	30,500
Retirement of long term debt	**(30,000)**	—	(55,500)
Retirement of preferred stock	**—**	(10,000)	(10,000)
Repayment of promissory notes	**(3,781)**	(2,449)	(7,790)
Dividends paid on preferred stock	**(3,700)**	(4,274)	(5,031)
Dividends paid on common stock	**(63,552)**	(66,262)	(69,592)
Payment for treasury stock	**(33,986)**	(36,819)	(46,433)
Corporate restructuring to establish holding company	**—**	(6,824)	—
Other, net	**113**	9,064	(51)
Total Financing	**(36,906)**	(68,064)	(63,889)
Decrease in cash and cash equivalents	**$ (1,592)**	$ (80)	$ (18,882)
Cash and cash equivalents at beginning of year	**$ 6,443**	$ 6,523	$ 25,405
Cash and cash equivalents at end of year	**$ 4,851**	$ 6,443	$ 6,523

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31,	2000	1999	1998
CASH PAID DURING THE PERIOD			
Interest paid (net of capitalized amount)	**$58,753**	$53,061	$43,793
Income taxes paid	**$46,438**	$58,750	$75,600
TRANSFER FROM UTILITY PLANT TO REGULATORY ASSET, NET	**$ —**	$54,255	$ —

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

NOTES TO FINANCIAL STATEMENTS

note 1

Summary of Accounting Principles

Holding Company Formation.

On August 2, 1999, Rochester Gas and Electric Corporation (RG&E) was reorganized into a holding company structure in accordance with the Agreement and Plan of Exchange between RG&E and RGS Energy Group, Inc. (the Company or RGS Energy). RG&E's common stock was exchanged on a share-for-share basis for RGS Energy's common stock. RG&E's preferred stock was not exchanged as part of the share exchange and will continue as shares of RG&E.

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 accounting principles generally accepted in the United States of America (GAAP) 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.

Basis of Presentation.

This is a combined report of RGS Energy and RG&E, a regulated Electric and Gas subsidiary. The Notes to Financial Statements apply to both RGS Energy and RG&E. RGS Energy's Consolidated Financial Statements include the accounts of RGS Energy and its wholly owned subsidiaries, including RG&E, and two non-utility subsidiaries, Energetix and RGS Development Corporation (RGS Development). RGS Energy's prior period consolidated financial statements have been prepared from RG&E's prior period consolidated financial statements, except that accounts have been reclassified to reflect RGS Energy's structure. RG&E's financial statements also include Energetix and RGS Development prior to August 2, 1999.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries RG&E, Energetix and RGS Development. All intercompany balances and transactions have been eliminated. Energetix's financial statements are consolidated with its wholly-owned subsidiary Griffith Energy (Griffith).

During the second quarter of 1998, the Company formed a new unregulated subsidiary, RGS Development. RGS Development was formed to pursue unregulated business opportunities in the energy marketplace. Through December 31, 2000, RGS Development operations have not been material to the Company's results of operation or its financial condition.

Summary of Significant Accounting Policies.

New York State Tax Changes.

On May 15, 2000 changes to the New York State tax laws were signed into law effective January 1, 2000. In June 2000 the Company recorded taxes in accordance with these changes. The effect of these changes was a reduction in the gross receipts tax rate, elimination of excess dividends taxes, and the imposition of a state income tax. As a result, deferred state income taxes were established in accordance with the transition rules to recognize timing differences between book and tax deductibility. This transition item results in a one-time tax benefit that has been deferred for future rate treatment in accordance with the Electric Settlement.

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). When circumstances change, the Company reviews the recoverability of goodwill based primarily upon an analysis of undiscounted cash flows from the acquired businesses. Other intangible assets include predominately dealer improvements, customer lists and covenants not to compete and are being amortized between one and fifteen years. Accumulated amortization amounted to $3.5 million and $1.7 million at December 31, 2000 and December 31, 1999 respectively.

Acquisitions.

In August 1998, Energetix acquired Griffith Oil, Co., Inc., for $31.5 million. The acquisition was accounted for as a purchase resulting in goodwill as reflected on the consolidated financial statements. The principal tangible assets acquired were vehicles, tanks, pumps, buildings and commodity inventory.

During 2000, Energetix acquired seven companies for an aggregate purchase price of $48.9 million, net of cash acquired. These acquisitions were recorded under the purchase method of accounting and, therefore, the purchase prices have been allocated to assets acquired and liabilities assumed based on estimated fair values, which are subject to further refinement. The results of operations of the acquired companies were included in the consolidated results of the Company from their respective acquisition dates.

Revenue Recognition.

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.

RG&E's regulated gas tariffs include a monthly gas adjustment clause, which allows RG&E to recover pipeline and storage capacity costs and the commodity cost of gas purchased for its customers. On an annual basis, RG&E reconciles the costs collected through the monthly gas adjustment clause and the actual gas costs for the prior twelve months.

RG&E eliminated its electric fuel cost adjustment clause in a prior rate settlement agreement with the PSC. This clause adjusted tariff rates monthly to reflect changes in the actual average cost of fuels.

Griffith revenues are recognized when products are delivered to customers or services have been rendered.

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% during the three-year period ended December 31, 2000. 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 3.1% in the three-year period ended December 31, 2000. The annual depreciation provision of Energetix is 7.8% in the three-year period ended December 31, 2000.

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 brokers.

Energetix has entered into electric and natural gas purchase commitments with numerous suppliers. These commitments support fixed price offerings to retail electric and gas customers. 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 Griffith's inventory or future purchases and sales of commodities used in Griffith'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, 2000 Griffith's net deferred gains on open hedge contracts were immaterial.

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). This statement was subsequently amended by SFAS 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133", and SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of SFAS 133". SFAS 133, as amended, established accounting and reporting standards for derivative instruments including certain derivative instruments embedded in other contracts and for hedging activities. This statement requires the Company to recognize all derivatives, with limited exception, as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The intended use of the derivatives and their designation as either a fair value or cash flow hedge determines when the gains or losses on the derivatives are reported in earnings and when they are reported as a component of other comprehensive income. The statement allows hedge accounting for the derivative instruments employed to manage market price risk, provided stringent documentation requirements are met prior to execution of the hedge transaction. Where applicable, the Company intends to elect hedge accounting for derivatives under the statement.

The Company has adopted SFAS 133 as of January 1, 2001. The cumulative effect of this change will not materially impact the Company's annual net income. This broad and complex standard requires, with limited exception, derivative transactions to be recognized and recorded on the Company's balance sheet at fair value. The balance sheet effect is an increase to assets and liabilities of approximately $9.5 million.

Jointly Owned Facilities.

The Company is a 14% owner of the Nine Mile Point Nuclear Plant Unit No. 2 (Nine Mile Two) generating facility. Nine Mile Two is operated by Niagara Mohawk Power Corporation (Niagara Mohawk). Each participant must provide its own financing for any additions to the facility. The Company's share of direct expenses associated with this unit is included in the appropriate operating expenses in the Consolidated Statement of Income.

Research and Development Costs.

Research and Development costs are charged to expense as incurred. Expenditures for the years 2000, 1999 and 1998 were $2.6 million, $2.9 million and $3.4 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.

Materials, Supplies and Fuels.

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

Nuclear Outage Costs.

The Company levelizes estimated incremental non-fuel expenses due to planned refueling outages at its two nuclear power plants. Such costs are levelized between refueling outages.

Stock-Based Compensation.

The Company accounts for its stock-based compensation using the fair value method in accordance with SFAS-123 (Accounting for Stock-Based Compensation). The aggregate amount recorded as a (benefit)/expense as a result of the Company's stock based compensation plans for the years 2000, 1999 and 1998 approximates $(1.9) million, $2.2 million and $5.9 million respectively.

Comprehensive Income.

There were no items of comprehensive income during the three-year period ended December 31, 2000; therefore, net income is equivalent to total comprehensive income.

Reclassifications.

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

note **2**

Nuclear-Related Matters

Nine Mile Nuclear Plants. On June 24, 1999, Niagara Mohawk and New York State Electric and Gas Corporation (NYSEG) announced their intention to sell their interests in the Nine Mile One and Nine Mile Two nuclear plants to AmerGen Energy Company, L.L.C. (AmerGen), a joint venture of PECO Energy and British Energy. Niagara Mohawk owns 41 percent of Nine Mile Two and 100 percent of Nine Mile One and NYSEG owns 18 percent of Nine Mile Two.

RG&E's 14 percent interest in Nine Mile Two was not included in the proposal but RG&E has a right of first refusal to buy the interests of the other owners of Nine Mile Two on terms at least as favorable as those offered. RG&E exercised its right of first refusal and broadened it to include Nine Mile One with which Nine Mile Two was paired in the proposal. However, in the ensuing discussions with the PSC staff it became clear that the transaction on the terms proposed would not be approved by the PSC.

On April 25, 2000, the PSC issued an order that allowed NYSEG and Niagara Mohawk to withdraw their petition to sell their interests in the Nine Mile plants to AmerGen. The order concluded that Nine Mile's market value is "greatly in excess of the original AmerGen purchase price" and that multiple entities are now interested in the Nine Mile plants. The order also concluded that "...failure for the utilities to determine the market value of the Nine Mile facilities at this time, through an open process, would raise serious prudence questions." With respect to stranded costs, the PSC order indicates that stranded costs cannot be finally quantified "until the disposition of the plants by the utilities is decided." The PSC's order does, however, observe that (1) a sale would be considered within its policy of separating generation from transmission and distribution, (2) a sale at current market values would constitute appropriate mitigation of stranded costs and (3) ratemaking treatment of a sale would be resolved in accordance with each company's competitive opportunities/restructuring order taking into account reduced risk and corollary divestiture effects.

After issuance of the PSC's order, RG&E decided to determine the market value of its interest in Nine Mile Two. On June 1, 2000, RG&E issued a press release announcing an auction process by RG&E, Central Hudson Gas & Electric Corporation (Central Hudson), NYSEG and Niagara Mohawk in connection with their ownership interests in Nine Mile Two and Niagara Mohawk's interest in Nine Mile One.

On December 11, 2000, RG&E, Niagara Mohawk, Central Hudson and NYSEG entered into an agreement to sell their ownership interests in Nine Mile Two to Constellation Nuclear, L.L.C. (Constellation Nuclear). Constellation Nuclear was the successful bidder in a competitive auction conducted for the plants. The Long Island Power Authority, an 18 percent owner of Nine Mile Two, is not participating in the sale

The purchase price for RG&E's 14 percent ownership interest in Nine Mile Two is $99.2 million, $49.6 million of which will be paid in cash at closing and $49.6 million of which will be paid in five equal annual principal installments plus interest at a rate of 11 percent pursuant to a five year promissory note. Principal and interest payments under the promissory note will total approximately $66 million unless the note is pre-paid. The purchase price is subject to adjustment at the time of closing. The aggregate purchase price for 82 percent of Nine Mile Two is $581 million. The aggregate purchase price, including cash payments at closing and payments of principal and interest to all of the sellers under the promissory notes, is $676.6 million for 82 percent of Nine Mile Two.

Also part of the transaction is a power purchase agreement whereby Constellation Nuclear has agreed to sell 90 percent of RG&E's 14 percent interest in Nine Mile Two's actual output back to RG&E for approximately 10 years at an average price of less than $35 per MWh over the term of the power purchase agreement.

After the completion of the power purchase agreement, a 10-year revenue sharing agreement begins. The revenue sharing agreement will provide RG&E with a hedge against electricity price increases and could provide RG&E additional revenue through 2021. The revenue sharing agreement provides that, to the extent market prices (for energy and capacity) exceed certain strike prices, 14 percent of the market value of Nine Mile Two's actual output (capped at 160 MW) above the strike price will be shared 80 percent to RG&E and 20 percent to Constellation Nuclear. When actual market prices are lower than strike prices, such negative amounts will be carried forward as credits against subsequent payments.

At closing, the sellers' pre-existing decommissioning funds will be transferred to Constellation Nuclear and Constellation Nuclear will assume the sellers' obligation to decommission Nine Mile Two.

The Nuclear Regulatory Commission (NRC), FERC, PSC and other regulatory bodies must approve the sale. Receipt of such regulatory approvals (including, without limitation, the PSC's authorization to establish a regulatory asset and return thereon for the full amount of RG&E's unamortized plant and capital costs of Nine Mile Two remaining after the closing of the sale), in form and substance reasonably satisfactory to RG&E, is a condition to RG&E's obligation to close the transaction. The transaction is targeted to close in mid-2001. At December 31, 2000, the net book value of RG&E's 14 percent interest in the Nine Mile Two generating facility was approximately \$360 million. RG&E also had investments in fuel of approximately \$8.9 million, transmission and distribution facilities of \$3.4 million and construction work in progress of \$4.6 million.

On January 31, 2001, RG&E, together with Niagara Mohawk, Central Hudson, NYSEG and Constellation Nuclear filed a Section 70 petition with the PSC. The petition requests that the PSC authorize the sellers to transfer to Constellation Nuclear their interests in Nine Mile Two in accordance with the rate treatment proposed. For RG&E, the rate treatment proposed includes full recovery of the regulatory asset remaining after the sale.

Prior to the events discussed above, the PSC had initiated a proceeding to examine the appropriate role of the nuclear power plants in the State in developing a competitive market for electricity. Collaborative efforts of the parties led to the development of a report on the subject which the PSC discussed at a July 1999 session without issuing an order. No significant activity has since occurred in the proceeding and RG&E cannot predict what the PSC may do to continue or conclude it. Since all nuclear plants in the state either have now been sold or are under contract to be sold, except for RG&E's Ginna Plant, the PSC could regard the proceeding as moot.

Decommissioning Trust. RG&E is collecting amounts in its electric rates for the eventual decommissioning of its Ginna Plant and for its 14 percent 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, RG&E has collected decommissioning costs of approximately \$182.9 million through December 31, 2000 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 RG&E's 14 percent 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. RG&E's plan, filed in 1990, consists of an external decommissioning trust fund covering both its Ginna Plant and its share of Nine Mile Two. Since 1990, RG&E has contributed \$148.7 million to this fund and, including realized and unrealized investment returns, the fund has a balance of \$244.5 million as of

December 31, 2000. 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, 2000 is $34.2 million. NRC regulations require biennial reports on the status of decommissioning trust funds and RG&E reported to the NRC that both the Ginna and Nine Mile Two decommissioning trusts exceed the NRC minimum funding amounts required as of December 31, 1999.

During December 2000, Constellation Energy was the successful bidder in an auction of the Company's 14 percent interest in the Nine Mile Two nuclear plant. As part of the purchase agreement, upon closing RG&E will transfer approximately $29.0 million to Constellation to fully fund RGE's pro-rata share of the plant's decommissioning liability. As of December 31, 2000, Nine Mile Two decommissioning assets were sufficient to meet RG&E's funding obligation. Upon completion of the sale, Constellation will assume all decommis-sioning liabilities for Nine Mile Two.

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 a 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 Nine Mile Two, 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 was held in January 1999. RG&E's potentially strandable assets in nuclear plants could be impacted by the outcome of this proceeding. The parties in this proceeding developed a collaborative, non-binding interim report entitled "Nuclear Generation and the Competitive Electric Market" which was issued in July 1999. RG&E is actively involved in this proceeding which is continuing. RG&E is unable to determine when this proceeding may conclude.

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 RG&E's nuclear plants. 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 a determination by the PSC.

Uranium Enrichment Decontamination and Decommissioning Fund. On June 12, 1998, 16 electric utilities from across the country, including RG&E, filed multi-count complaints against the United

States government in the United States District Court for the Southern District of New York. The suits challenge the constitutionality of a $2.25 billion retroactive assessment imposed by 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 matter is proceeding through the courts.

The assessments for Ginna and RG&E's share of Nine Mile Two are estimated to total $22.1 million, excluding inflation and interest. Installments aggregating approximately $14.7 million have been paid through 2000. A liability has been recognized on the financial statements along with a corresponding regulatory asset. For the two facilities RG&E's liability at December 31, 2000 is $11.4 million ($9.6 million as a long-term liability and $1.8 million as a current liability). RG&E is recovering these costs in rates.

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, at the earliest. In December 1996 the DOE notified RG&E that the DOE would not start accepting 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 RG&E in June 1985. RG&E estimates the fees, including accrued interest, owed to the DOE to be $97.3 million at December 31, 2000. RG&E is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Nuclear Waste Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of approximately one mill ($.001) per KWH of nuclear energy generated and sold. This charge (approximately $4.0 million per year) is currently being collected from customers and paid to the DOE pursuant to PSC authorization. RG&E 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 RG&E'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 RG&E completed installation of seven high-capacity spent fuel racks in the Ginna 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.

Litigation

Spent Nuclear Fuel Litigation. The federal Nuclear Waste Act obligated the DOE to remove disposal spent nuclear fuel (SNF) from utilities' powerplants by January 31, 1998 (statutory deadline). Since the mid-1980s, RG&E and other nuclear plant owners and operators have paid substantial fees to the DOE to fund that obligation (Nuclear Waste Fund). The DOE has not satisfied its obligation under the Nuclear Waste Act and there is no way to determine when and if it will begin removing SNF for disposal.

The DOE's failure to meet its statutory deadline has given rise to numerous lawsuits in both the U.S. Court of Appeals for the District of Columbia and the U.S. Court of Federal Claims.

Although the DOE has been found to have breached its obligations, it is not possible to predict the outcome of these cases, the future course of the DOE obligation or the resolution of the spent nuclear fuel movement and storage concern that underlies it. Similarly, the ultimate outcome of nuclear waste legislation in Congress that could address these and related concerns, is uncertain. The court rulings on the DOE's default in meeting its obligation to remove SNF for disposal 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. RG&E and other nuclear utilities continue to work toward those objectives in judicial, legislative and administrative initiatives.

note 3

Regulatory Matters

Regulatory Assets

With PSC approval RG&E has deferred certain costs rather than recognize them as expense 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, Accounting for the Effects of Certain Types of Regulation. These deferred costs are shown as regulatory assets on the Company's and RG&E's Balance Sheets. Such cost deferral is appropriate in a 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 RG&E was no longer allowed to defer some or a portion of these costs under SFAS-71, these assets would be adjusted accordingly, which may include up to the entire amount being written off.

Below is a summary of RG&E's regulatory assets as of December 31, 2000 and 1999:

	Millions of Dollars	
	2000	1999
Kamine Settlement	**$179.1**	$187.5
Income Taxes	**101.9**	129.5
Oswego Plant Sale	**74.4**	78.6
Deferred Environmental SIR costs	**16.6**	20.5
Uranium Enrichment Decommissioning Deferral	**12.7**	13.9
Gas Deferred Fuel	**(1.6)**	9.3
Labor Day 1998 Storm Costs	**9.3**	8.5
Other, net	**18.8**	18.4
Total–Regulatory Assets	**$411.2**	$466.2

- ***Kamine Settlement:*** This amount results from a settlement resolving all litigation, releasing all claims and terminating all electricity purchase obligations under a power purchase agreement.
- ***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.
- ***Oswego Plant Sale:*** This amount results from the sale of RG&E's interest in the Oswego generation facility including closing costs and the buyer's assumption of RG&E's obligations under a transmission services agreement.
- ***Deferred Environmental Site Investigation/Remediation Costs:*** These costs represent RG&E's share of the estimated costs to investigate and perform certain remediation activities at both RG&E-owned and non-owned sites with which it may be associated. RG&E has recorded a regulatory

asset representing the remediation obligations to be recovered from ratepayers, subject to the terms of the Electric Settlement.

- ***Uranium Enrichment Decommissioning Deferral:*** The Energy Policy Act of 1992 requires utilities to contribute amounts to the DOE based on the amount of uranium enriched by the DOE for each utility. This amount is mandated to be paid to the DOE through the year 2007. The recovery of these costs is through base rates of fuel.
- ***Gas Deferred Fuel:*** These costs result from a PSC-approved monthly gas adjustment clause which allows RG&E to recover pipeline and storage capacity costs and the commodity cost of gas purchased for its customers. On an annual basis, RG&E reconciles the costs collected through the monthly gas adjustment clause and the actual gas costs for the prior twelve months.
- ***Labor Day 1998 Storm Costs:*** These costs result from a 1998 Labor Day storm. Under the Electric Settlement, RG&E 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. RG&E filed a petition with the PSC notifying it of the deferral of these storm costs.

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. An example includes 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, 2000 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 the amount could be significant. Strandable assets, if any, could be written down for impairment of recovery based on SFAS-121, "Accounting for the Impairment of Long Lived Assets and for Long Lived Assets to be Disposed of", which requires write-down of long-lived assets whenever events or circumstances occur that indicate the carrying amount of a long-lived asset may not be recoverable.

At December 31, 2000 RG&E believed that its regulatory assets are probable of recovery. The Electric Settlement does not impair the opportunity of RG&E to recover its investment in these assets. However, the Electric Settlement provides for the non-nuclear generation to-go costs to be subject to market forces during the current Settlement term. Should the costs of non-nuclear generation exceed market prices, the Company may no longer be able to apply SFAS-71. These costs have been below prevailing market prices. The PSC issued an Opinion and Order Instituting Further Inquiry on March 20, 1998 to address issues surrounding nuclear generation. RG&E is unable to determine when this proceeding may conclude. The ultimate determination in this proceeding or any proceeding to consider RG&E's proposed sale of its interest in Nine Mile Two as discussed under "Nuclear-Related Matters" could have an impact on strandable assets and the recovery of nuclear costs.

In a competitive natural gas market, strandable assets would arise where customers migrate away from dependence on RG&E for full service, leaving RG&E with surplus pipeline and storage capacity, as well as natural gas supplies under contract. RG&E has been restructuring its transportation, storage and supply portfolio to reduce its potential exposure to strandable assets. Regulatory developments referred to under "Gas Settlements" 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.

Gas Settlements

PSC Gas Restructuring 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 addressed 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 PSC has encouraged settlement negotiations with each gas utility pertaining to the transition to a fully competitive gas market. RG&E, the PSC Staff and other interested parties engaged in settlement discussions in response to the specific requirements of the Gas Policy Statement. In January 2001, RG&E reached agreement with PSC Staff and other parties on a comprehensive rate and restructuring proposal for its natural gas business, as contemplated in the PSC's Gas Policy Statement.

Gas Retail Access Settlements. On January 25, 2001, RG&E reached agreement with PSC Staff and other parties on a comprehensive rate and restructuring proposal for its natural gas business (the Gas Rates and Restructuring Proposal), as contemplated in the PSC's Gas Policy Statement.

Since mid-1998, RG&E, PSC Staff and other parties have engaged in settlement negotiations regarding RG&E's rates and restructuring. These negotiations have resulted in two previous agreements among RG&E, PSC staff and several other parties. The first was implemented in September 1999 and addressed the following issues: a capacity release revenue imputation, capacity cost mitigation measures, a timetable for public filing and resumption of negotiations, and improvement of RG&E's retail access program. The September 1999 agreement was approved by the PSC in an Order issued September 30, 1999.

Pursuant to the September 1999 agreement, RG&E, on January 28, 2000, made a filing addressing various issues pertaining to RG&E's natural gas business, including proposals for restructuring that business and facilitating migration from fully bundled sales service to retail service provided by natural gas marketers. Certain issues presented by the January 28, 2000 filing, principally relating to the commencement of a single-retailer retail access program for gas, in substantially the same form as currently in effect for electric retail access (see "Energy Choice" heading), and the establishment of a "backout credit" to be paid to natural gas marketers serving retail customers, were resolved in a June 2000 Gas Settlement.

The Gas Rates and Restructuring Proposal is intended to resolve all issues identified by the parties and not resolved in either the September 1999 settlement or the June 2000 Gas Settlement, as approved by the PSC. It is anticipated that this Proposal will be approved by the PSC in February 2001 and made effective on March 1, 2001, although no assurance may be given as to such approval or its timing.

The Gas Rates and Restructuring Proposal contains a number of features that are intended to extend for different periods. The two most significant periods are the Rate Term, which applies principally to rate-related provisions and extends from July 1, 2000 through June 30, 2002, and the Rate and Restructuring Program which applies to most other provisions and extends from the date of approval of the Proposal through March 31, 2004. The principal features of the Proposal are as follows:

(1) for the purpose of setting base, or local delivery, rates for the period beginning July 1, 2000, natural gas revenues shall be decreased a total of $2,806,000 from the levels in effect on June 30, 2000. This rate level is based on an agreed-upon return on equity of 11.00 percent;

(2) base rates will be adjusted effective March 1, 2001 to reflect the revenue requirements decrease. Because the current base rates that will be in effect through February 28, 2001 are higher than those agreed to by the parties, RG&E, in March 2001, will pass back to all its retail gas customers a temporary credit applied to rates, on a volumetric basis, equal to the amount of the reduction in rates for the period July 1, 2000 through February 28, 2001;

(3) RG&E is allowed to defer any prudent and verifiable cost for recovery after the Rate Term of the Proposal, subject to PSC approval;

(4) in the event that RG&E achieves a return on equity in excess of 12.5 percent in any Rate Year covered by this Proposal, 90 percent of the excess over that level shall be deferred for the benefit of customers;

(5) RG&E shall be entitled to defer any costs associated with mandates and catastrophic events that occur during the Rate Term of this Proposal. If the incremental cost impact of any individual mandate or any individual catastrophic event exceeds $600,000 per rate year, RG&E is entitled to defer the entire amount for recovery. Amounts deferred shall be recovered from RG&E customers after the Rate Term of this Proposal;

(6) RG&E is entitled to defer for recovery after June 30, 2002, all incremental expenditures for competition implementation costs to the extent that such costs exceed $300,000 per year;

(7) if migration to retail access is expected to exceed 30 percent of the small-volume customer market (i.e., customers eligible under Service Classification No. 5 - Small General Service) during the Rate Term of the Proposal, the parties will meet to discuss the PSC Transition Cost Surcharge with a view to considering changes that would reduce the allocation of capacity costs to Service Classification No. 1 - General Service customers;

(8) RG&E is authorized to implement a Retail Access Capacity Program, contemplated to begin before the 2001-2002 heating season, pursuant to which RG&E would release pipeline capacity it currently holds to marketers serving customers in RG&E's service area. This Program will help to avoid stranded capacity costs that might otherwise result from migration of customers to marketers;

(9) RG&E will implement a Capacity Incentive Program, consisting of a Capacity Cost Incentive and a Capacity Cost Imputation. Both elements are intended to encourage aggressive management of RG&E's capacity costs. The Capacity Cost Incentive is designed to share, between RG&E and its customers, the savings resulting from the difference between a base level of capacity costs and the actual capacity costs achieved. The Capacity Cost Imputation is intended to provide customers with a guaranteed level of short-term savings through the gas cost adjustment provision. "Short-term" refers to periods of one year or less. "Savings" refers to capacity release savings, as well as net revenues from off-system sales, if any. The imputed level of savings will be $1,100,000 per year for the period beginning April 1, 2001 and extending through June 30, 2002. The level will then be $500,000 per year for the period beginning July 1, 2002 and extending through March 31, 2004;

(10) RG&E will implement a Low-Income Program for customers who require assistance. The Low-Income Program will be funded through a surcharge in customer bills; and

(11) RG&E will implement a Service Quality Performance Program to be effective as of January 1, 2001 through at least June 30, 2002. This Program establishes performance targets for six specific measures of service and provides for a maximum overall penalty of 42 basis points of gas return on equity for failure to meet the minimum levels specified.

PSC Assignment of Gas Capacity. Under a March 1996 Order, the PSC permitted RG&E and other gas distribution companies to assign to marketers, as necessary, to serve their customers the pipeline and storage capacity held by RG&E. In its Gas Policy Statement, the PSC ordered that the 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. On March 24, 1999, the PSC issued an Order Concerning Assignment of Capacity for all gas utilities in the State, generally requiring the removal of restrictions on customer migration from utility service to service from marketers. RG&E has complied with the PSC's directives. The Retail Access Capacity Program and the Capacity Incentive Program, contained in the Gas Rates and Restructuring Proposal will, if adopted by the PSC, help mitigate potential stranded costs resulting from migration of customers to marketers.

FERC Gas Market Proposals. On February 9, 2000, FERC issued Order No. 637, its final rule addressing "Regulation of Short-Term Natural Gas Transportation Services" and "Regulation of Interstate Natural Gas Transportation Services". On June 5, 2000 FERC issued Order No. 637-A providing clarification and additional guidance. On July 26, 2000 FERC issued Order No. 637-B upholding Orders No. 637 and No. 637-A. Order No. 637 as clarified revises FERC's regulations to improve the efficiency of the gas transportation market and to provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity. Specifically, Order No. 637 as clarified:

(1) waives the price ceiling for released capacity of less than one year until September 30, 2002;

(2) permits pipelines to propose peak, off-peak and term differentiated rates, provided that they still satisfy the revenue and cost constraints of traditional rate-making, and excess revenues are split with firm customers;

(3) revises FERC's regulations on scheduling procedures, capacity segmentation and pipeline penalties;

(4) states that the right of first refusal will apply in the future to contracts for 12 consecutive months or more of service at maximum rates; and

(5) amends and supplements reporting requirements to require interstate pipelines to report additional information on transactions, operationally available capacity, and an expanded index of customers.

Order No. 637 as clarified requires each pipeline to make a compliance filing. All of the pipelines' initial compliance filings were submitted to FERC by August 15, 2000. FERC has established technical and settlement conference procedures for many of the pipelines, including those on which RG&E holds transportation capacity. FERC staff has indicated at the respective pipeline settlement and technical conferences that no action on various pipeline proposals will be taken prior to April 2001, after the heating season has ended.

Neither RGS nor RG&E can predict what effects, if any, FERC's initiatives and the related pipeline tariff changes will have on future operations or the financial condition of RGS or RG&E.

note 4 OPERATING SEGMENT FINANCIAL INFORMATION

The Company has 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 GAAP and PSC accounting policies. The Unregulated segment's financial records are maintained in accordance with GAAP.

During the reported periods, substantially all revenues are from United States sources, and substantially 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. 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 electricity, gasoline, natural gas, oil, propane, and appliance warranty and repair. RGS Development was formed to pursue unregulated business opportunities in the energy marketplace.

(thousands of dollars)	2000	1999	1998
Regulated Electric			
Operating Income	**$ 124,149**	$ 120,599	$ 119,937
Revenues from External Customers	**$ 721,737**	$ 698,745	$ 687,100
Revenues from Intersegment Transactions	**$ 78,175**	$ 44,510	$ 8,974
Interest Revenue	**$ 10,986**	$ 10,799	$ 1,694
Depreciation and Amortization	**$ 99,662**	$ 102,946	$ 102,123
Regulatory Amortization	**$ 18,219**	$ 14,287	$ 15,080
Nuclear Fuel Amortization	**$ 15,493**	$ 15,622	$ 18,138
Interest Expense	**$ 50,045**	$ 45,653	$ 36,122
Operating Income Tax Expense	**$ 49,614**	$ 55,752	$ 61,477
Capital Expenditures, net	**$ 109,962**	$ 78,599	$ 96,206
Total Identifiable Assets	**$1,915,002**	$1,925,809	$1,941,622

(thousands of dollars)	2000	1999	1998
Regulated Gas			
Operating Income	**$ 22,801**	$ 19,343	$ 10,393
Revenues from External Customers	**$322,412**	$278,659	$274,540
Revenues from Intersegment Transactions	**$ 1,856**	$ 420	$ 594
Interest Revenue	**$ 413**	$ 315	$ 424
Depreciation and Amortization	**$ 12,448**	$ 12,548	$ 12,867
Regulatory Amortization	**$ 494**	$ 220	$ 1,461
Interest Expense	**$ 10,877**	$ 9,648	$ 9,030
Operating Income Tax Expense/(Benefit)	**$ 9,837**	$ 8,580	$ (92)
Capital Expenditures, net	**$ 30,405**	$ 24,746	$ 28,075
Total Identifiable Assets	**$462,470**	$438,290	$433,029

(thousands of dollars)	2000	1999	1998
Unregulated			
Operating Income/(Loss)	**$ 2,078**	$ 543	$ (2,460)
Revenues from External Customers	**$484,001**	$275,063	$81,419
Interest Revenue	**$ 1,198**	$ 398	$ 158
Depreciation and Amortization	**$ 3,325**	$ 2,450	$ 834
Goodwill Amortization	**$ 749**	$ 751	$ 278
Interest Expense	**$ 2,571**	$ 2,171	$ 916
Operating Income Tax Expense/(Benefit)	**$ 354**	$ (50)	$ (1,255)
Capital Expenditures, net	**$ 2,129**	$ 4,994	$ 5,005
Total Assets	**$179,010**	$ 90,580	$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 Electric 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. Additionally, the operations of RGS Development are included in Other (Income) and Deductions in the RGS Energy Group, Inc. Consolidated Statement of Income. The operations of RGS Development are not significant. The total assets identified by operating segment do not equal the total Company consolidated amounts as shown in the RGS Energy Group, Inc. Consolidated Balance Sheet. This is due to the elimination of certain intersegment transactions during consolidation, and certain common assets unidentifiable by segment. Intersegment eliminations result from intercompany receivables and payables from affiliates. A reconciliation follows:

(thousands of dollars)	2000	1999	1998
Revenues			
Regulated Electric	**$ 721,737**	$ 698,745	$ 687,100
Regulated Gas	**322,412**	278,659	274,540
Unregulated	**484,001**	275,063	81,419
Total	**$1,528,150**	$1,252,467	$1,043,059
Reported on Consolidated Income Statement	**1,448,119**	1,207,537	1,033,491
Difference to reconcile	**$ 80,031**	$ 44,930	$ 9,568
Intersegment Revenues			
Regulated Electric from Unregulated	**$ 78,175**	$ 44,510	$ 8,974
Regulated Gas from Unregulated	**$ 1,856**	$ 420	$ 594
Total Intersegment	**$ 80,031**	$ 44,930	$ 9,568

(thousands of dollars)	2000	1999
Assets		
Regulated Electric	**$1,915,002**	$1,925,809
Regulated Gas	**462,470**	438,290
Unregulated	**179,010**	90,580
Cash and Cash Equivalents, Regulated Operations	**4,851**	6,443
Unamortized Debt Expense	**16,602**	17,984
Other	**617**	367
Intersegment eliminations	**(12,754)**	(16,599)
Total Assets	**$2,565,798**	$2,462,874

note **5**

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, 2000 and 1999:

(Millions)	Pension Benefits		Other Benefits	
	2000	1999	2000	1999
Change in benefit obligation				
Benefit obligation at beginning of year	**$473.8**	$516.8	**$80.2**	$99.0
Service cost	**6.3**	6.9	**1.0**	1.1
Interest cost	**35.2**	32.7	**5.9**	5.5
Plan amendments	**13.8**	(0.5)	**0.0**	0.9
Actuarial (gain) loss	**11.5**	(48.7)	**2.7**	(22.0)
Curtailments	**0.0**	(3.5)	**0.0**	0.0
Special termination benefits	**0.0**	8.4	**0.0**	0.0
Benefits paid	**(41.3)**	(38.3)	**(4.5)**	(4.3)
Benefit obligation at end of year	**$499.3**	$473.8	**$85.3**	$80.2
Change in plan assets				
Fair value of plan assets at beginning of year	**$768.3**	$706.4	**$0.0**	$0.0
Actual return on plan assets	**(15.0)**	99.5	**0.0**	0.0
Company contribution	**0.7**	0.7	**4.5**	4.3
Benefits paid	**(41.3)**	(38.3)	**(4.5)**	(4.3)
Fair value of plan assets at end of year	**$712.7**	$768.3	**$0.0**	$0.0
Funded status	**$213.4**	$294.5	**$(85.3)**	$(80.2)
Unrecognized actuarial (gain) loss	**(260.9)**	(352.5)	**(8.0)**	(10.8)
Unrecognized prior service cost	**20.7**	8.6	**11.5**	12.6
Unrecognized net transition obligation	**0.3**	0.8	**27.3**	29.8
Accrued benefit	**$(26.5)**	$(48.6)	**$(54.5)**	$(48.6)
Weighted-average assumptions as of December 31				
Discount rate	**7.25%**	7.50%	**7.25%**	7.50%
Expected return on plan assets	**8.50%**	8.50%		
Rate of compensation increase	**5.00%**	5.00%		

(Millions)	Pension Benefits 2000	Pension Benefits 1999	Pension Benefits 1998	Other Benefits 2000	Other Benefits 1999	Other Benefits 1998
Components of net periodic (benefit) cost						
Service cost	**$ 6.3**	$ 6.9	$ 7.0	**$ 1.0**	$ 1.1	$ 1.1
Interest cost	**35.2**	32.7	32.9	**5.9**	5.5	6.0
Expected return on plan assets	**(54.0)**	(49.6)	(44.8)	**0.0**	0.0	0.0
Unrecognized transition obligation	**0.5**	0.5	0.5	**2.5**	2.5	2.8
Amortization of prior service	**1.7**	0.8	0.9	**1.1**	1.0	0.6
Recognized actuarial (gain) loss	**(11.0)**	(5.5)	(4.3)	**(0.1)**	0.0	0.0
Net periodic (benefit) cost	**$(21.3)**	$(14.2)	$ (7.8)	**$10.4**	$10.1	$10.5

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits on a defined dollar basis. In 2000, the health care benefit consists of a contribution of up to $230 per retiree per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay.

In addition 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 2000, 1999, and 1998 were $3.1 million, $2.8 million, and $2.5 million, respectively.

During 1999, a generation plant was shut down creating a staff reduction of 36 employees, resulting in a net curtailment charge of $4.9 million, including $8.4 million cost of special termination benefits provided to affected employees offset by a curtailment gain of $3.5 million. Pursuant to the Company's settlement agreement, this charge has been deferred.

note 6

LONG TERM DEBT

First Mortgage Bonds of RG&E

%	Series	Due	(Thousands of Dollars) Principal Amount December 31 2000	1999
9 3/8	PP	Apr. 1, 2021	**$100,000**	$100,000
8 1/4	QQ	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		Jan. 14, 2000	**—**	30,000
7.15		Feb. 10, 2003	**39,000**	39,000
7.13		Mar. 3, 2003	**1,000**	1,000
7.64		Mar. 15, 2023	**33,000**	33,000
7.66		Mar. 15, 2023	**5,000**	5,000
7.67		Mar. 15, 2023	**12,000**	12,000
6.375		July 30, 2003	**40,000**	40,000
7.45		July 30, 2023	**40,000**	40,000
5.84		Dec. 22, 2008	**50,000**	50,000
7.60		Oct. 27, 2009	**100,000**	100,000
			$580,500	$610,500
Net bond discount			**(368)**	(430)
Less: Due within one year			**—**	30,000
Total			**$580,132**	$580,070

(a) The 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 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 RG & E. 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.

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

Sinking and improvement fund requirements aggregate $0.3 million 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.

Sinking fund requirements and bond maturities for the next five years are $100 million in 2002, and $80 million in 2003.

Promissory Notes and Other

		(Thousands of Dollars) December 31	
Issued	Due	**2000**	1999
September 2, 1998(a)	September 1, 2033	**$ 25,500**	$ 25,500
August 19, 1997(a)	August 1, 2032	**101,900**	101,900
December 1, 1998(b)	March 31, 2014	**88,530**	92,311
Total		**$215,930**	$219,711
Less: RG&E Due within one year		**4,227**	3,781
Total RG&E		**$211,703**	$215,930
August 3, 1998(c)	August 3, 2005	**17,545**	21,054
November, 2000 (d)	November, 2005	**13,617**	—
Other Long Term Debt of Subsidiaries		**8,730**	2,273
Total		**$251,595**	$239,257
Less: RGS Due within one year		**7,868**	3,862
Total RGS		**$243,728**	$235,395

(a) Issued in connection with NYSERDA's Pollution Control Revenue Bonds. Payment of the principal of, and interest on the Series A Bonds is guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation. RG&E 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.

(b) The Promissory Note was issued in connection with the Kamine Global Settlement Agreement and is collateralized by a mortgage, the lien for which is subordinate to the lien of the First Mortgage. During 1999 and 2000, RG&E made payments totaling $9.6 million for each year. The Company expects to make future payments totaling $10.6 million per year.

(c) The Promissory Note was issued in connection with the acquisition of Griffith by Energetix and is secured by a pledge of the stock of Griffith. RGS has made a financial guarantee on behalf of Energetix which obligates RGS in the event of a default by Energetix in payments under the Note. Beginning in 1998 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.

(d) The $13.6 million Promissory Note was issued in connection with the acquisition of Burnwell by Griffith. RGS has made a financial guarantee on behalf of Griffith which obligates RGS in the event of a default by Griffith. Beginning in 2001, payments of principal are made in five annual installments and interest accrues at the rate of 8% per year.

Based on an estimated borrowing rate at year-end 2000 of 6.88% for long-term debt with similar terms and average maturities (11 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $863 million at December 31, 2000.

Based on an estimated borrowing rate at year-end 1999 of 7.60% for long-term debt with similar terms and average maturities (11 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $829 million at December 31, 1999.

note 7

PREFERRED AND PREFERENCE STOCK OF RG&E

Type by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	720,000*
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, 2000	(Thousands) December 31, 2000	1999	Optional Redemption (per share)#
4	F	120,000	**$12,000**	$12,000	$105
4.10	H	80,000	**8,000**	8,000	101
4 3/4	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:

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.

At December 31, 2000 and 1999 there were 250,000 shares of Series V, 6.60% preferred stock shares outstanding with a value of $25,000,000.

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 2000 of 5.46% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (7.25 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $27 million at December 31, 2000.

Based on an estimated dividend rate at year-end 1999 of 6.40% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (8.25 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $26 million at December 31, 1999.

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 1,436,700 and 1,435,600 of the shares were purchased in 2000 and 1999 respectively.

Common Stock.

At December 31, 2000, there were 100,000,000 shares of 1¢ par value Common Stock authorized, of which 34,577,426 were outstanding. No shares of Common Stock are reserved for warrants, conversions, or other rights. There were 1,883,854 shares of Common Stock reserved and unissued for employees under the 1996 Performance Stock Option Plan, as further described below.

	RGS Shares Outstanding	RGS Amount (Thousands)	RG&E Shares Outstanding	RG&E Amount (Thousands)
Balance, December 31, 1998	37,378,813	$653,297	37,378,813	$653,297
RG&E Shares	(38,885,813)		(38,885,813)	
RGS Shares	38,885,813		38,885,813	
Additional Paid in Capital		486		486
Repurchase Plan	(1,435,600)	(36,819)	1,507,000	(36,819)
Decrease in Capital Stock Expense		52		52
Balance, December 31, 1999	35,943,213	$617,016	38,885,813	$617,016
Shares Issued through Stock Plans	70,913	1,772		
Additional Paid in Capital		717		
Repurchase Plan	(1,436,700)	(33,986)		(33,986)
Decrease in Capital Stock Expense		50		50
Balance, December 31, 2000	34,577,426	$585,569	38,885,813	$583,080

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 1¢ 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 2000, the Board of Directors granted 267,576 options at an exercise price of $20.50 per share. These options are exercisable for a period of 10 years, and vest three years after the options are granted. The average grant date option fair value and exercise prices are $6.28 and $20.50 respectively. None of these options were exercised during 2000, and are included in the summary of stock option activity presented on the following page. During 2000, 70,913 shares were exercised from the 1997 grant date.

In 1999, the Board of Directors granted 177,322 options at an exercise price of $29.69 per share. These options are exercisable for a period of 10 years, and vest three years after the options are granted. The average grant date option fair value and exercise prices are $9.11 and $29.69 respectively. None of these options were exercised during 1999, and are included in the summary of stock option activity presented on the following page.

In 1998, the Board of Directors granted 27,984 options at an exercise price of $33.91 per share and 15,157 options at an exercise price of $31.00 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.

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.

The weighted average contractual remaining life for all options issued is 7.3 years and exercise prices range from $19.06 to $33.91 at December 31, 2000.

Compensation expense associated with the options granted is reflected in 2000, 1999 and 1998 net income. The compensation expense associated with the options granted was $1.1 million in 2000, $.5 million in 1999 and $.2 million in 1998. The compensation expense was calculated using the shorter of the anticipated or actual vesting period. 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 from 6.19% to 6.86% for 2000, 4.61% to 5.16% for 1999 and 5.54% to 5.65% for 1998, expected dividend yield of 8.78% for 2000, 6.03% for 1999 and 9.44% for 1998 and expected stock volatility of 18% for 2000, 19% for 1999 and 17% for 1998. The fair value estimate also includes an amount for the value of dividend rights associated with each option.

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

	Options	Weighted Average Exercise Price
Options granted 1998	43,141	$32.89
Options exercised	(23,466)	$19.06
Outstanding at 12/31/98	563,651	$20.63
Vested at 12/31/98	369,256	$19.45
Available for future grant at 12/31/98	1,402,000	
Options granted 1999	177,322	$29.69
Options forfeited	(10,884)	$19.06
Outstanding at 12/31/99	730,089	$22.85
Vested at 12/31/99	369,256	$19.45
Available for future grant at 12/31/99	1,224,678	
Options granted 2000	267,576	$20.50
Options exercised	(70,913)	$19.06
Outstanding at 12/31/00	926,752	$21.77
Vested at 12/31/00	298,343	$19.51
Available for future grant at 12/31/00	957,102	

note 9

Earnings Per Share

Basic earnings per share (EPS) is computed by dividing income available to common shareholders by the weighted average number 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)	2000	1999	1998
Basic EPS:			
Net Income Available to Common Shareholders	**$91,859**	$89,497	$89,296
Average Shares	**35,178**	36,665	38,462
Per-Share Amount	**$2.61**	$2.44	$2.32
Diluted EPS:			
Effect of Dilutive Securities Stock Option Plan	**103**	92	138
Net Income Available to Common Shareholders	**$91,859**	$89,497	$89,296
Average Shares	**35,281**	36,757	38,600
Per-Share Amount	**$2.60**	$2.44	$2.31

RGS had 202,402, 177,322 and 0 of antidilutive stock options at December 31, 2000, 1999 and 1998 respectively.

note 10

Short-Term Debt

On December 31, 2000, RGS had total short-term debt outstanding of $122.4 million, comprised of RG&E short-term debt of $98.0 million and Energetix short-term debt of $24.4 million. At December 31, 1999, RGS had total short-term debt outstanding of $10.5 million, comprised entirely of Energetix short-term debt. The weighted average interest rate on short-term debt outstanding at year-end 2000 was 6.94% for RG&E and 8.43% for Energetix. The weighted average interest rates for borrowings during 2000 and 1999 were 6.94% and 5.44% for RG&E and 7.47% and 5.95% for Energetix, respectively.

RG&E has a $90 million revolving credit agreement which terminates on December 31, 2001. In order to be able to use this credit facility, RG&E created a subordinate mortgage which secures borrowings under the revolving credit agreement that might otherwise be restricted by this provision of its Charter. Outstandings under this facility were $65 million at December 31, 2000. In addition to the $90 million credit facility, RG&E has two $25 million unsecured revolving credit agreements which expire December 13, 2001 and January 18, 2002, respectively. At December 31, 2000, there were no borrowings under either unsecured facility.

Griffith, a subsidiary of Energetix, has a $33 million revolving credit agreement that terminates July 31, 2003. Borrowings under this agreement are secured by personal property of Griffith. In addition, RGS executed a credit support agreement on behalf of Griffith that requires RGS to make principal and interest payments on certain Griffith long-term debt obligations, should Griffith not meet minimum financial covenants as required under its revolving credit agreement. Energetix has also made a financial guarantee on behalf of Griffith that obligates Energetix in the event of a Griffith default.

RG&E 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 RG&E's accounts receivable and totaled $23.0 million at December 31, 2000. In addition, RG&E has unsecured lines of credit totaling $27 million available from several banks, at their discretion. RG&E had $10.0 million outstanding on its uncommitted facilities as of December 31, 2000.

RG&E's Charter provides that it may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of its 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, 2000, RG&E would be able to incur approximately $116.9 million of additional unsecured debt under this provision

note 11

Income Taxes

The provision for income taxes is distributed between operating income 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 RGS Energy Group. Amounts for Rochester Gas & Electric are not materially different.

Note 11 continued on page 64

(Thousands of Dollars)	2000	1999	1998
Operating Income			
Current:			
Federal	**$51,038**	$ 72,137	$ 70,541
State	**11,513**	0	0
Total current expense	**62,551**	72,137	70,541
Deferred:			
Federal	**(1,213)**	(7,884)	(9,156)
State	**(1,506)**	0	0
Total deferred expense	**(2,719)**	(7,884)	(9,156)
Income taxes attributable to operating income	**59,832**	$64,253	$61,385
Other Income			
Current:			
Federal	**8,392**	(2,614)	(1,614)
State	**207**	0	0
Total current expense	**8,599**	(2,614)	(1,614)
Deferred:			
Federal	**(5,167)**	5,703	4,562
State	**(146)**	0	0
Deferred investment tax credit	**(2,141)**	(4,223)	(2,432)
Total deferred expense	**(7,454)**	1,480	2,130
Income taxes attributable to non-operating income	**1,145**	(1,134)	516
Total income tax expense	**$60,977**	$63,119	$61,901

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

(Thousands of Dollars)	2000	1999	1998
Net Income	**$ 95,559**	$ 93,580	$ 94,138
Add: income tax expense	**60,977**	63,119	61,901
Income before income taxes	**156,536**	$156,699	$156,039
Computed tax expense at statutory tax rate	**$ 54,788**	$ 54,845	$ 54,614
Increases (decreases) in tax resulting from:			
State income tax expense, net of federal benefit	**6,544**	0	0
Difference between tax depreciation and amount deferred	**3,503**	7,103	9,366
Deferred investment tax credit	**(2,141)**	(4,223)	(2,432)
Miscellaneous items, net	**(1,717)**	5,394	353
Total income tax expense	**$ 60,977**	$ 63,119	$ 61,901

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

(Thousands of Dollars)	2000	1999	1998
Federal & State			
Nuclear decommissioning	**$ (37,982)**	$ (28,811)	$ (24,849)
Accelerated depreciation	**214,798**	218,001	214,521
Deferred investment tax credit	**21,631**	23,023	25,768
Depreciation previously flowed through	**120,750**	127,448	146,953
Pension	**(12,306)**	(21,503)	(20,161)
Deferred NYS deduction	**(12,594)**	0	0
Other	**(16,510)**	536	(15,260)
Total	**$277,787**	$318,694	$326,972

SFAS-109 "Accounting for Income Taxes" requires that a deferred tax liability 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 of Rochester Gas & Electric and will be amortized consistent with the depreciation of these accounts. The net amount of the additional liability at December 31, 2000 and 1999 was

$102 million and $129 million, respectively. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

note 12

Commitments and Other Matters

Capital Expenditures

The Company's 2001 construction expenditures program is currently estimated at $164 million for RGS of which $161 million is for RG&E. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

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 monitors its activities in order to determine the impact of its activities on the environment and to ensure compliance with various environmental requirements. RGS has recorded a total liability of approximately $24.4 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. RG&E 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.

RG&E-owned Electric and Gas Waste Site Activities. RG&E is conducting proactive SIR efforts at eight RG&E-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 RG&E is conducting a program to restore the other two sites. RG&E has recorded a liability of approximately $21.9 million for SIR efforts at the eight RG&E-owned sites in the Rochester, New York area.

Superfund and Non-owned Other Sites. RG&E has been or may be associated as a potentially responsible party at nine sites not owned by it and has recorded estimated liabilities of approximately $.5 million in connection with SIR efforts at these sites. RG&E has signed orders on consent for five of these sites.

Griffith Facilities. RGS's subsidiary, Energetix, acquired Griffith in 1998. 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 this review 35 sites were identified which are currently undergoing evaluation and/or remediation. Using historical New York State Department of Environmental Conservation (NYSDEC) remedial actions as a guide, Energetix estimates the accrual of aggregate cleanup costs discounted at 6.8 percent over the future five-year period for all active sites approximates $1.3 million.

In November 2000, Griffith acquired both Burnwell® Gas and the New York Fuels Division of AllEnergy Marketing Company, L.L.C. Energetix performed Phase I and Phase II environmental investigations on all ten properties in the Burnwell acquisition and identified ten items requiring some type of remedial measures. With regard to the AllEnergy acquisition, Energetix reviewed Phase I and Phase II environmental reports provided by AllEnergy together with the investigative reports prepared by independent consulting firms during the prior two years. As a result of certain identified environmental conditions a $1.5 million accrual has been established for AllEnergy.

New York Initiatives. By letter dated May 25, 2000, the NYSDEC issued a Notice of Violation ("NOV") to RG&E, asserting that certain "modifications" to Russell and Beebee Stations during 1983-1987 resulted in a "significant increase in the capacity to emit sulfur dioxide." The NOV alleges that, as a result, permits required by the federal Clean Air Act and the State Environmental Conservation Law should have been obtained by RG&E prior to beginning the "modifications." The NOV asserts that RG&E may be liable for civil penalties of up to $10,000 per day, per violation, as well as subjected to unspecified injunctive relief. The allegations in the NOV are similar to those being made by the United States Department of Justice, on behalf of the United States Environmental Protection Agency, in enforcement cases relating to a number of electric utility coal-fired power plants in the midwest and southeast. The NOV invited RG&E to request an informal conference with the NYSDEC. Since July 2000, RG&E has had several such informal meetings with the NYSDEC. On the merits of the allegation, RG&E does not believe it has engaged in prohibited activities at either station.

The Governor of New York directed the NYSDEC to require electric generators to further reduce acid rain-causing emissions. The Governor has proposed extending the existing NOx control program under which RG&E's Russell Station operates to a year-round program (it is currently in effect only for the five-month ozone season). In addition, the Governor has proposed that there be a targeted reduction of approximately 50% in SO2 emissions below the existing Acid Rain Phase II limits. The state emission reductions would be phased-in beginning January 1, 2003 and be complete by January 1, 2007. Since this is only a proposed change, and subject to review, comment, and modification, no accurate estimate of its economic impact on RG&E can be made at this time.

Other Matters

Lease Agreements. RG&E and Energetix lease a total of 20 properties for administrative offices and operating activities and lease a number of vehicles. The total lease obligations charged to operations was $5.6 million, $5.4 million and $4.8 million in 2000, 1999 and 1998, respectively, including $1.7 million and $1.5 million in 2000 and 1999, respectively, for Energetix. RG&E's estimated annual lease obligations for the years 2001-2005 will be $5.6 million, $4.1 million, $3.3 million, $2.9 million and $2.6 million, respectively. Energetix estimated annual lease obligations for the years 2001-2005 will be $1.8 million, $1.4 million, $1.2 million, $0.7 million and $0.5 million, respectively. Commitments under capital leases after 2005 are not significant.

Purchase Commitments. The Company has entered into electric and natural gas purchase commitments with numerous suppliers. Certain of these commitments support fixed price offerings to retail electric and gas customers.

Gas Supply, Storage and Pipeline Commitments. In connection with its regulated gas business, RG&E has long-term commitments with a number of interstate natural gas pipeline companies to provide transportation and storage-related services. The table below sets forth RG&E's estimated commitments at December 31, 2000 for the next eight years based on current contractual volumes and represent demand charges priced at current pipeline tariff rates:

Interstate Pipeline and Storage Commitments

Year	$ in thousands
2001	$ 59,670
2002	59,083
2003	59,083
2004	50,111
Therafter until 2012	117,918

With respect to firm gas supply commitments, RG&E currently contracts for gas supply on a seasonal basis, so therefore, has no long-term gas supply obligations.

Long Term Contracts for the Purchase of Electric Power. As of January 1, 2001, RG&E had long-term contracts to purchase electric power from the New York Power Authority.

Facility	Expiration date of contract	Purchased capacity in MW	Estimated annual capacity cost
FitzPatrick nuclear facility	one year's notice by either party	50	$3,384,000
Niagara–hydroelectric project	2007	100	$1,200,000
St. Lawrence–hydroelectric project	2007	55	$660,000
Blenheim-Gilboa–pumped storage generating station	2002	150	$4,140,000

The purchased capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts, was approximately, in millions, $13.9, $12.1, and $11.5 for the years 2000, 1999, and 1998 respectively. RG&E continues to have a contract with NYPA to purchase for resale power for NYPA's Power for Jobs customers.

Report of Management

The management of RGS Energy Group, Inc. (RGS) and its subsidiaries 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 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.

Financial statements have been examined by PricewaterhouseCoopers LLP, independent accountants, in accordance with generally accepted auditing standards. Their examination includes a review of the system of internal accounting control and such tests and other procedures necessary to express an opinion as to whether the financial statements are presented fairly in all material respects in conformity with generally accepted accounting principles. The report of PricewaterhouseCoopersLLP is presented on page 34.

The Audit Committee of the RGS Board of Directors is responsible for reviewing and monitoring the 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, 2000, RGS and its subsidiaries maintained an effective system of internal control over the preparation of their published financial statements.

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

Interim Financial Data

In the opinion of RGS and RG&E, 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 RGS and RG&E's business and the availability of surplus electricity. The sum of the quarterly earnings per share may not equal the annual earnings per share due to rounding.

(Thousands of Dollars)

Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings Per Common Share (in dollars) Basic	Diluted
RGS						
December 31, 2000	$437,259	$32,946	$23,827	$22,902	$.66	$.66
September 30, 2000	314,304	26,962	14,095	13,170	.38	.38
June 30, 2000	310,705	35,482	18,295	17,369	.49	.49
March 31, 2000	385,851	53,689	39,342	38,418	1.07	1.07
December 31, 1999[1]	$325,788	$33,982	$24,605	$23,681	$.65	$.65
September 30, 1999[1]	279,853	29,528	16,891	15,964	.44	.44
June 30, 1999[1]	275,805	27,219	14,822	13,706	.37	.37
March 31, 1999[1]	326,091	50,189	37,262	36,146	.97	.97
RG&E						
December 31, 2000	$303,047	$31,535	$23,111	$22,186	—	—
September 30, 2000	223,686	27,139	14,796	13,871	—	—
June 30, 2000	226,566	36,097	19,279	18,354	—	—
March 31, 2000	290,850	52,179	38,343	37,418	—	—
December 31, 1999	$249,204	$33,737	$24,696	$23,394	—	—
September 30, 1999	239,348	29,990	17,708	17,159	—	—
June 30, 1999	275,805	27,219	14,822	13,706	—	—
March 31, 1999	326,091	50,189	37,262	36,146	—	—
December 31, 1998	$286,507	$22,173	$15,015	$14,088	$.37	$.37
September 30, 1998	253,750	35,128	25,213	23,908	.62	.62
June 30, 1998	210,724	22,620	15,655	14,350	.37	.37
March 31, 1998	282,510	48,145	38,255	36,950	.95	.95

[1]*Reclassified for comparative purposes.*

Common Stock and Dividends

Earnings/Dividends	RGS 2000	RGS/ RGE 1999	RGE 1998
Earnings per share			
–basic	$2.61	$2.44	$2.32
–diluted	$2.60	$2.44	$2.31
Dividends paid per share	$1.80	$1.80	$1.80

Shares/Shareholders	RGS 2000	RGS/ RG&E 1999	RG&E 1998
Number of shares (000's)			
Weighted average			
–basic	35,178	36,665	38,462
–diluted	35,281	36,757	38,600
Actual number at December 31	34,577	35,943	37,379
Common share price at December 31	$32.44	$20.56	$31.25
Number of registered shareholders at December 31	25,518	27,258	28,995

RGS Energy Group, Inc.

On August 2, 1999, Rochester Gas and Electric Corporation (RG&E) was reorganized into a holding company structure pursuant to an Agreement and Plan of Share Exchange (Exchange Agreement) between RG&E and RGS Energy Group, Inc. (RGS). As part of the reorganization, all of the outstanding shares of RG&E common stock were exchanged on a share-for-share basis for shares of RGS and RG&E became a subsidiary of RGS. Certificates for shares of RG&E common stock are automatically valid as certificates for RGS and do not have to be replaced. The transfer does not affect the value of the stock or RGS's dividend policy. RG&E shareholders approved the Exchange Agreement on April 29, 1999.

Tax Status of Cash Dividends

Cash dividends paid in 2000, 1999 and 1998 were 100 percent taxable for federal income tax purposes.

Dividend Policy

RG&E has paid cash dividends quarterly on its common stock without interruption since it became publicly held in 1949. Since its formation in August 1999, RGS has continued this historic practice of dividend payments.

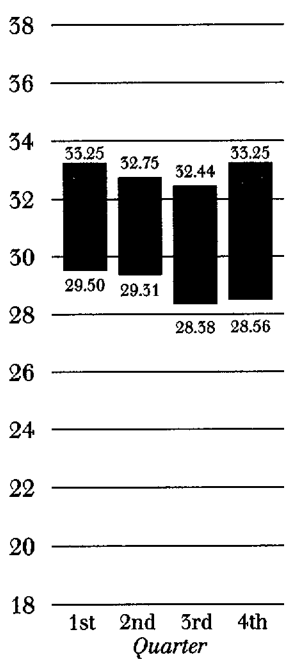
The ability of RGS to pay common stock dividends is governed by the ability of RGS's subsidiaries to pay dividends to RGS. Because RG&E is by far the largest of RGS's subsidiaries, it is expected that for the foreseeable future the funds required by RGS to enable it to pay dividends will be derived predominantly from the dividends paid to RGS by RG&E. In the future, dividends from subsidiaries other than RG&E may also contribute to RGS's ability to pay dividends. RG&E's ability to make dividend payments to RGS will depend upon the availability of retained earnings and the needs of its utility business. RG&E's Certificate of Incorporation provides for the payment of dividends on its common stock out of the surplus net profits (retained earnings) of RG&E. In addition, pursuant to the PSC order approving the formation of RGS, RG&E may pay dividends to RGS of no more than 100% of RG&E's net income calculated on a two-year rolling basis. The calculation of net income for this purpose excludes non-cash charges to income resulting from accounting changes or certain PSC-required charges, as well as charges that may arise from significant unanticipated events. This condition does not apply to dividends that would be used to fund the remaining portion of RG&E's $100 million authorization for unregulated operations (about $13 million at December 31, 2000).

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 2001, RGS paid a cash dividend of $.45 per share on its Common Stock. The January 2001 dividend payment is equivalent to $1.80 on an annual basis.

Stock Price

RGS's common stock has been traded on the New York Stock Exchange under the symbol "RGS" since August 2, 1999. Prior to that date, RG&E's common stock was traded on the New York Stock Exchange, also under the symbol "RGS". RG&E's common stock is no longer traded because it is all held by RGS. The closing stock price for RGS common stock was $31.31 on January 26, 2001.

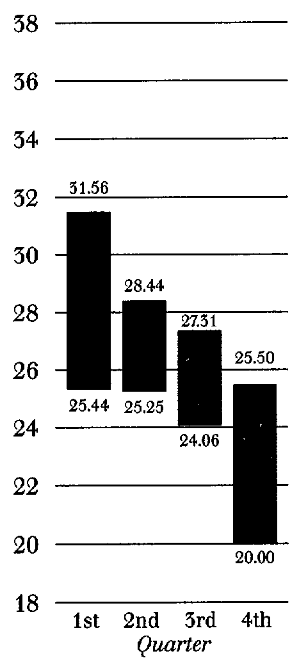
1998
Range of
Common Stock Price
(in Dollars)



Dividends Paid per Share
1998 per Quarter
(in Dollars)

0.45	0.45	0.45	0.45

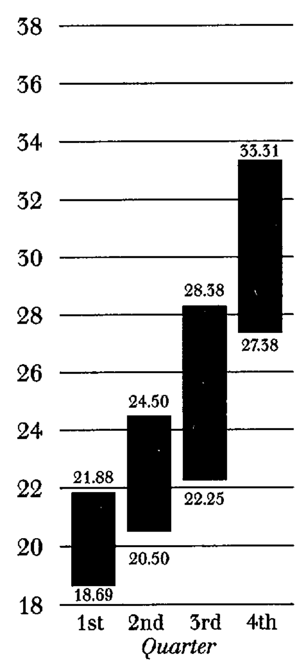
1999
Range of
Common Stock Price
(in Dollars)



Dividends Paid per Share
1999 per Quarter
(in Dollars)

0.45	0.45	0.45	0.45

2000
Range of
Common Stock Price
(in Dollars)



Dividends Paid per Share
2000 per Quarter
(in Dollars)

0.45	0.45	0.45	0.45

Selected Financial Data

Consolidated Summary of Operations

(Millions of Dollars) Year Ended December 31,	RGS Consolidated 2000	RG&E 2000	RGS Consolidated 1999	RG&E 1999	1998	1997	1996
Operating Revenues							
Electric	**$ 731.0**	**$ 721.7**	$ 702.8	$ 700.2	$ 687.6	$ 700.3	$ 707.8
Gas	**340.0**	**322.4**	284.5	281.6	274.7	336.3	346.2
Other	**377.1**	**—**	220.3	108.6	71.2	—	—
Total Operating Revenues	**1,448.1**	**1,044.1**	1,207.6	1,090.4	1,033.5	1,036.6	1,054.0
Operating Expenses							
Fuel Expenses							
Fuel for electric generation	**48.9**	**48.9**	49.3	49.3	54.0	47.7	40.9
Purchased electricity	**85.9**	**80.9**	54.3	53.0	27.0	28.3	46.5
Gas purchased for resale	**208.5**	**192.0**	151.5	149.0	155.5	196.6	202.3
Unregulated fuel expenses	**340.3**	**—**	189.4	91.5	59.5	—	—
Total Fuel Expenses	**683.6**	**321.8**	444.5	342.8	296.0	272.6	289.7
Operating Revenues Less Fuel Expenses	**764.5**	**722.3**	763.1	747.6	737.5	764.0	764.3
Other Operating Expenses							
Operations and maintenance excluding fuel expenses	**313.7**	**313.7**	297.9	297.9	301.6	315.1	313.2
Unregulated operating and maintenance expenses excluding fuel	**31.1**	**—**	26.5	14.2	13.5	—	—
Depreciation and amortization	**116.2**	**112.1**	118.7	117.3	116.1	116.5	105.6
Taxes–local, state and other	**94.6**	**90.1**	114.6	112.6	118.0	121.8	126.9
Income tax	**59.8**	**59.5**	64.4	64.5	60.3	65.3	69.4
Total Other Operating Expenses	**615.4**	**575.4**	622.1	606.5	609.5	618.7	615.1
Operating Income	**149.1**	**146.9**	141.0	141.1	128.0	145.3	149.2
Other (Income) and Deductions							
Allowance for other funds used during construction	**(0.8)**	**(0.8)**	(0.7)	(0.7)	(0.4)	(0.4)	(0.7)
Income tax	**1.1**	**0.2**	(1.3)	(1.1)	1.7	(3.7)	(3.5)
Other, net	**(9.5)**	**(8.9)**	(8.0)	(8.1)	(13.4)	3.4	(0.6)
Total Other (Income) and Deductions	**(9.2)**	**(9.5)**	(10.0)	(9.9)	(12.1)	(0.7)	(4.8)
Interest Charges							
Long term debt	**58.0**	**56.7**	53.7	53.1	43.3	44.6	48.6
Other, net	**6.0**	**5.5**	4.8	4.5	3.4	6.6	9.3
Allowance for borrowed funds used during construction	**(1.3)**	**(1.3)**	(1.1)	(1.1)	(0.7)	(0.6)	(1.4)
Total Interest Charges	**62.7**	**60.9**	57.4	56.5	46.0	50.6	56.5
Net Income	**95.6**	**95.5**	93.6	94.5	94.1	95.4	97.5
Preferred Stock Dividend Requirements	**3.7**	**3.7**	4.1	4.1	4.8	5.8	7.5
Net Income Applicable to Common Stock	**$ 91.9**	**$ 91.8**	$ 89.5	$ 90.4	$ 89.3	$ 89.6	$ 90.0
Earnings per Common Share–Basic	**$2.61**		$2.44		$2.32	$2.30	$2.32
Earnings per Common Share–Diluted	**$2.60**		$2.44		$2.31	$2.30	$2.32
Cash Dividends Declared per Common Share	**$1.80**		$1.80		$1.80	$1.80	$1.80

Condensed Consolidated Balance Sheet

(Millions of Dollars) At December 31,	RGS Consolidated 2000	RG&E 2000	RGS Consolidated 1999	RG&E 1999	1998	1997*	1996*
Assets							
Utility Plant	**$3,396**	**$3,349**	$3,254	$3,231	$3,327	$3,234	$3,160
Less: Accumulated depreciation and amortization	**2,005**	**1,990**	1,876	1,874	1,863	1,714	1,569
	1,391	**1,359**	1,378	1,357	1,464	1,520	1,591
Construction work in progress	**111**	**111**	95	96	98	74	70
Net Utility Plant	**1,502**	**1,470**	1,473	1,453	1,562	1,594	1,661
Current Assets	**307**	**277**	220	203	203	242	250
Intangible Assets	**51**	**—**	21	—	21	—	—
Deferred Debits and Other Assets	**706**	**704**	749	747	667	432	450
Total Assets	**$2,566**	**$2,451**	$2,463	$2,403	$2,453	$2,268	$2,361
Capitalization and Liabilities							
Capitalization							
Long Term Debt	**$ 824**	**$ 792**	$ 816	$ 796	$ 758	$ 587	$ 647
Preferred stock redeemable at option of RG&E	**47**	**47**	47	47	47	47	67
Preferred stock subject to mandatory redemption	**25**	**25**	25	25	25	35	45
Common shareholders' equity:							
Common stock	**703**	**700**	700	700	700	699	696
Retained earnings	**182**	**166**	153	138	129	109	91
Less: Treasury stock at cost	**117**	**117**	83	83	46	—	—
Total common shareholders' equity	**768**	**749**	770	755	783	808	787
Total Capitalization	**$1,664**	**$1,613**	$1,658	$1,623	$1,613	$1,477	$1,546
Long Term Liabilities	**131**	**129**	126	125	124	110	106
Current Liabilities	**317**	**258**	169	150	183	176	145
Deferred Credits and Other Liabilities	**454**	**451**	510	505	533	505	564
Total Capitalization and Liabilities	**$2,566**	**$2,451**	$2,463	$2,403	$2,453	$2,268	$2,361

**Reclassified for comparative purposes.*

Financial Data

At December 31	2000	1999	1998	1997	1996
RGS					
Capitalization Ratios (a) (percent)					
Long-term debt	**52.3**	**51.9**	—	—	—
Preferred stock	**4.1**	**4.1**	—	—	—
Common shareholders' equity	**43.6**	**44.0**	—	—	—
Total	**100.0**	**100.0**	—	—	—
Book Value per Common Share–Year End	**$22.19**	**$21.43**	—	—	—
Rate of Return on Average Common Equity (percent)	**11.82**	**11.53**	—	—	—
Embedded Cost of Senior Capital (percent)					
Long-term debt	**7.31**	**7.20**	—	—	—
Preferred stock	**5.24**	**5.24**	—	—	—
Interest Coverages					
Before federal income taxes (incld. AFUDC)	**3.39**	**3.68**	—	—	—
(excld. AFUDC)	**3.36**	**3.65**	—	—	—

RG&E

At December 31	2000	1999	1998	1997	1996
Capitalization Ratios (a) (percent)					
Long-term debt	**52.0**	**51.8**	49.8	43.0	44.7
Preferred Stock	**4.2**	**4.2**	4.2	5.2	6.9
Common shareholder's equity	**43.8**	**44.0**	46.0	51.8	48.4
Total	**100.0**	**100.0**	100.0	100.0	100.0
Book Value per Common Share–Year End	**$21.71**	**$21.00**	$20.94	$20.80	$20.24
Rate of Return on Average Common Equity (percent)	**12.12**	**11.76**	11.22	11.00	11.41
Embedded Cost of Senior Capital (percent)					
Long-term debt	**7.29**	**7.21**	7.20	7.32	7.33
Preferred stock	**5.24**	**5.24**	5.56	5.80	6.26
Interest Coverages					
Before federal income taxes (incld. AFUDC)	**3.49**	**3.74**	4.41	4.06	3.82
(excld. AFUDC)	**3.46**	**3.71**	4.38	4.04	3.79

(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.

Electric Department Statistics

Year Ended December 31,	RGS 2000	RG&E 2000	RGS 1999*	RG&E 1999*	1998	1997	1996
Electric Revenue (millions)							
Residential	**$247.9**	**$247.9**	$ 273.2	$ 273.2	$ 250.1	$ 252.5	$ 254.9
Commercial	**161.0**	**161.0**	171.1	171.1	203.3	210.6	215.8
Industrial	**103.9**	**103.9**	115.5	115.5	130.8	144.3	153.3
Municipal and Other	**35.8**	**35.8**	48.4	48.3	58.9	72.1	66.8
Electric revenue – retail customers	**548.6**	**548.6**	608.2	608.1	643.1	679.5	690.8
Energy Marketers	**99.5**	**99.5**	65.2	65.2	15.0	—	—
Other Electric Utilities	**73.6**	**73.6**	25.3	25.3	29.0	20.8	16.9
Other unregulated electric revenues	**9.3**	—	4.0	1.5	0.5	—	—
Total electric revenues	**731.0**	**721.7**	702.7	700.1	687.6	700.3	707.7
Electric Expense (millions)							
Fuel for electric generation	**48.9**	**48.9**	49.3	49.3	54.0	47.7	40.9
Purchased electricity	**81.0**	**80.9**	53.0	53.0	27.0	28.3	46.5
Other unregulated fuel expense	**4.9**	—	1.3	—	—	—	—
Operation and maintenance	**253.4**	**253.4**	233.8	233.8	233.4	246.3	246.2
Unregulated operation and maintenance	**2.0**	—	2.2	1.0	2.0	—	—
Depreciation and amortization	**100.9**	**99.6**	103.0	103.0	102.1	103.4	92.6
Taxes–local, state and other	**66.6**	**65.1**	84.6	84.0	89.6	91.1	95.0
Total electric expense	**557.7**	**547.9**	527.2	524.1	508.1	516.8	521.2
Operating Income before Income Tax	**173.3**	**173.8**	175.5	176.0	179.5	183.5	186.5
Income tax	**49.0**	**49.6**	55.2	55.5	61.5	61.8	61.9
Operating Income from Electric Operations (millions)	**$124.3**	**$124.2**	$120.3	$120.5	$118.0	$121.7	$124.6
Electric Sales–MWH (000's)							
Residential	**2,154**	**2,154**	2,269	2,269	2,120	2,139	2,133
Commercial	**1,680**	**1,680**	1,783	1,783	2,036	2,119	2,062
Industrial	**1,557**	**1,557**	1,762	1,762	1,914	2,011	2,011
Municipal and Other	**391**	**391**	482	482	517	537	521
Total retail sales	**5,782**	**5,782**	6,296	6,296	6,586	6,806	6,726
Energy Marketers	**1,134**	**1,134**	763	763	175	—	—
Other electric utilities	**1,636**	**1,636**	1,112	1,112	1,499	1,219	995
Other unregulated sales	**162**	—	23	2	—	—	—
Total electric sales	**8,714**	**8,552**	8,194	8,173	8,260	8,025	7,721
Electric Distribution Customers at December 31 (Thousands)							
Residential	**313**	**313**	311	311	310	309	307
Commercial	**32**	**32**	30	30	30	31	31
Industrial	**1**	**1**	1	1	1	1	1
Municipal and Other	**5**	**5**	2	2	3	3	3
Total electric customers	**351**	**351**	344	344	345	344	342
Electricity Generated and Purchased–MWH (000's)							
Fossil	**1,548**	**1,548**	1,693	1,693	1,963	1,665	1,513
Nuclear	**4,926**	**4,926**	4,735	4,735	5,324	5,120	4,094
Hydro	**208**	**208**	133	133	190	228	249
Pumped storage	**67**	**67**	233	233	233	239	247
Less energy for pumping	**(101)**	**(101)**	(350)	(350)	(348)	(358)	(370)
Other	—	—	1	1	—	1	1
Total generated–net	**6,648**	**6,648**	6,445	6,445	7,361	6,894	5,733
Purchased	**2,422**	**2,389**	2,089	2,068	1,466	1,302	2,437
Total electric energy	**9,070**	**9,037**	8,534	8,513	8,827	8,195	8,171
RGE System Net Capability–MW at December 31							
Total system net capability	**1,382**	**1,382**	1,382	1,382	1,588	1,614	1,617
RGE Net Peak Load–MW	**1,367**	**1,367**	1,433	1,433	1,388	1,421	1,305

**Reclassified for comparative purposes.*

Gas Department Statistics

Year Ended December 31,	RGS 2000	RG&E 2000	RGS 1999*	RG&E 1999*	1998*	1997*	1996*
Gas Revenue (millions)							
Residential	**$ 6.7**	**$ 6.7**	$ 5.7	$ 5.7	$ 2.9	$ 5.9	$ 6.0
Residential spaceheating	**250.2**	**250.2**	212.8	212.8	201.7	249.1	246.9
Commercial	**36.3**	**36.3**	31.1	31.1	40.2	51.9	52.1
Industrial	**3.4**	**3.4**	3.0	3.0	4.2	5.8	6.2
Municipal and other	**9.0**	**9.0**	19.7	19.7	24.9	23.6	35.1
Gas revenue–retail customers	**305.6**	**305.6**	272.3	272.3	273.9	336.3	346.3
Marketers	**16.8**	**16.8**	6.4	6.4	.8	—	—
Other unregulated gas revenues	**17.6**	—	5.8	2.9	—	—	—
Total gas revenue	**340.0**	**322.4**	284.5	281.6	274.7	336.3	346.3
Gas Expense (millions)							
Gas purchased for resale	**192.0**	**192.0**	147.0	147.0	155.5	196.6	202.3
Other unregulated fuel expense	**16.5**	—	4.4	2.0	—	—	—
Operation and maintenance	**60.3**	**60.3**	64.0	64.0	68.2	68.8	67.0
Unregulated operation and maintenance	**3.9**	—	2.8	1.3	2.5	—	—
Depreciation	**14.8**	**12.5**	12.6	12.6	12.9	13.1	13.0
Taxes–local, state and other	**28.0**	**25.0**	28.6	27.8	28.2	30.8	31.9
Total gas expense	**315.5**	**289.8**	259.4	254.7	267.3	309.3	314.2
Operating Income before Income Tax	**24.5**	**32.6**	25.1	26.9	7.4	27.0	32.1
Income Tax (Benefit)	**8.8**	**9.8**	8.0	8.4	(0.1)	3.4	7.6
Operating Income from Gas Operations (millions)	**$ 15.7**	**$ 22.8**	$ 17.1	$ 18.5	$ 7.5	$ 23.6	$ 24.5
Gas Sales–Therms (millions)							
Residential	**6.0**	**6.0**	5.9	5.9	3.6	5.8	6.5
Residential spaceheating	**261.8**	**261.8**	264.0	264.0	239.7	285.4	299.1
Commercial	**41.3**	**41.3**	43.2	43.2	53.6	65.7	70.5
Industrial	**4.2**	**4.2**	4.5	4.5	6.1	7.8	9.3
Municipal	**4.6**	**4.6**	5.7	5.7	6.4	7.3	8.1
Total retail sales	**317.9**	**317.9**	323.4	323.4	309.4	372.0	393.5
Transportation of customer-owned gas	**239.6**	**239.6**	200.0	200.0	163.6	166.1	167.8
Other unregulated sales	**36.6**	—	12.5	7.1	1.2	—	—
Total gas sold and transported	**594.1**	**557.5**	535.9	530.5	474.1	538.1	561.3
Gas Distribution Customers at December 31 (Thousands)							
Residential	**14.3**	**14.3**	16.5	16.5	16.9	16.3	16.7
Residential spaceheating	**251.1**	**251.1**	246.5	246.5	249.7	243.3	240.7
Commercial	**19.6**	**19.6**	19.5	19.5	19.7	19.2	19.0
Industrial	**.8**	**.8**	.8	.8	.8	.8	.9
Municipal	**1.0**	**1.0**	1.1	1.1	1.1	1.1	1.0
Transportation	**.7**	**.7**	.7	.7	.7	.7	.7
Total gas customers	**287.5**	**287.5**	285.1	285.1	288.9	281.4	279.0
RGE, Gas–Therms (millions)							
Purchased for resale	**230.7**	**230.7**	200.0	200.0	203.7	274.4	279.4
Gas from storage	**95.0**	**95.0**	126.2	126.2	111.2	104.3	122.8
Other	**1.7**	**1.7**	2.2	2.2	1.5	1.4	1.1
Total gas available–RGE	**327.4**	**327.4**	328.3	328.3	316.3	380.2	403.3
Total Daily Capacity–RGE Millions of Therms at December 31*	**4,402**	**4,402**	4,493	4,493	4,380	4,380	4,480
Max. daily throughput, Therms–RG&E (millions)	**4,305**	**4,305**	4,008	4,008	3,584	4,114	4,023
Degree Days (Calendar Month)							
For the period (thousands)	**6.6**	**6.6**	6.3	6.3	5.7	6.9	7.0
Percent colder (warmer) than normal	**(1.9)**	**(1.9)**	(6.6)	(6.6)	(15.9)	2.8	3.9

**Reclassified for comparative purposes.*

***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

RGS business and financial information is available on line as well as by phone.

RGS by Phone

Access RGS 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 RGS's quarterly earnings announcement or request a copy, including financial statements, by fax or by mail.

RGS on Line

RGS's web site features the latest news and financial information, including quarterly dividend and earnings announcements, financial statements and press releases. Visit us on line at http://www.rgs-energy.com.

RGS 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 RGS should contact Mark J. Graham, Manager of Investor Relations at (716) 724-8176.

Corporate Address

RGS Energy Group, Inc.
89 East Avenue
Rochester, NY 14649-0001
(716) 771-4444

Shareholder Services

Shareholder services representatives are available weekdays from 9 a.m. to 6 p.m. eastern standard time through 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 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 RGS Common Stock are paid quarterly around the 25th of January, April, July and October. Dividends on the RG&E 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

RGS 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 RGS Common Stock and the shares have to be held in your name, meaning they can't be in a broker street name account.

RG&E 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

RGS's 2001 annual meeting of shareholders will be held at the Hyatt Regency Rochester, on Wednesday, April 25, 2001 at 11 am.

Stock Listings

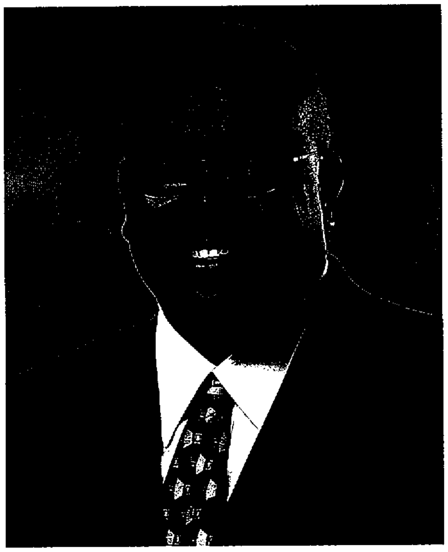
RGS's Common Stock is listed on the New York Stock Exchange and is identified by the stock symbol RGS. RG&E Preferred Stock issues are traded on the over-the-counter market.

Form 10-K Annual Report

Shareholders may obtain a copy of RGS's 2000 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 RGS.

Management Appointment
as of February 1, 2001

Officer Appointment



William L. Thomas

William L.Thomas has been appointed as vice-president of Human Resource Services, Mr. Thomas had been vice-president, Human Resources at Bausch & Lomb's Vision Care Business Unit. Prior to that he was manager, Human Resources: Development & Manufacturing for Xerox Corporation.

Mr. Thomas is a cum laude graduate of Benedict College with a BS Degree in business administration. Long active in Rochester area community affairs, he is chairman of the board of the Rochester Urban League and a board member of several other community organizations. He resides in Henrietta, New York, with his wife, Kim.

Mr. Thomas replaces Wilfred J. Schrouder, Jr. who retired after 39 years of service.

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Directors and Officers
as of January 1,2001

RGS Energy Group, Inc. and Rochester Gas and Electric Corporation ~ Directors

Angelo J. Chiarella †√
Director of Planning,
FJF Architects, LLP

Allan E. Dugan *‡
Executive Vice-President and President, Worldwide Business Services, Xerox Corporation

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

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

Jay T. Holmes *√
Attorney and Business Consultant

G. Jean Howard †√
Executive Director, Wilson Commencement Park

Samuel T. Hubbard, Jr. †
President and Chief Executive Officer, High Falls Brewing Company, LLC

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

Cornelius J. Murphy *‡
Senior Vice-President, Goodrich & Sherwood Associates, Inc.

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, RGS Energy Group, Inc. and Rochester Gas and Electric Corporation

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

RGS Energy Group, Inc. ~ Officers

Chairman, President and Chief Executive Officer:
Thomas S. Richards

Senior Vice-Presidents:
J. Burt Stokes, *Chief Financial Officer* *
Michael T. Tomaino, *General Counsel*
Michael J. Bovalino
Paul C. Wilkens

Secretary: David C. Heiligman
Treasurer: Mark Keogh
Controller: William J. Reddy
Assistant Treasurer: Kathleen C. Spellane
Assistant Controller: Joseph J. Syta

Rochester Gas and Electric Corporation ~ Officers

Chairman, President and Chief Executive Officer:
Thomas S. Richards

Senior Vice-Presidents:
J. Burt Stokes, *Corporate Services and Chief Financial Officer* *
Michael T. Tomaino, *General Counsel*
Paul C. Wilkens, *Generation*

Vice-Presidents:
Louis L. Bellina, *Customer Relations*
David C. Heiligman, *Corporate Secretary*
David J. Irish, *Fossil/Hydro Operations*
Mark Keogh, *Treasurer*
Robert C. Mecredy, *Nuclear Operations*
Clifton B. Olson, *Energy Supply*
Jessica S. Raines, *Support Services*
William J. Reddy, *Controller*
Paul G. Ruganis, *Information Services*
Wilfred J. Schrouder, Jr., *Human Resource Services* *
William L. Thomas, *Human Resource Services* **
Michael B. Whitcraft, *Energy Delivery*
Joseph A. Widay, *Plant Manager, Ginna Station*

Assistant Treasurer: Kathleen C. Spellane
Assistant Controller: Joseph J. Syta

Energetix, Inc. ~ Officers

President and Chief Executive Officer:
Michael J. Bovalino

Vice-Presidents:
John A. Hamilton, *Operations*
Christian B. Modesti, *Finance and Chief Financial Officer*
James T. DiStefano, *Sales and Marketing*

* Retired effective February 1, 2001
** Effective February 1, 2001

RGS Energy Group, Inc.
89 East Avenue
Rochester, NY 14649-0001
(716) 771-4444

An Equal Opportunity Employer

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