Green Mountain Power Corporation
163 Acorn Lane
Colchester, Vermont 05446

Green Mountain Power Corporation

2000 Annual Report to Shareholders

The clouds of uncertainty are lifting…

Financial and Operating Highlights

	2000	1999	Percent Change
Financial Data			
Operating revenues	**$277,326,000**	$251,048,000	10.5
Operating expenses	**$272,066,000**	$243,102,000	11.9
Net income (loss), continuing operations	**($ 305,000)**	3,061,000	*
Net income (loss), discontinued operations	**($ 6,549,000)**	($ 7,279,000)	*
Net income (loss) applicable to common stock	**($ 6,854,000)**	($ 4,218,000)	*
Total utility plant	**$298,496,000**	$288,711,000	3.4
Common Share Data			
Weighted average shares outstanding	**5,491,000**	5,361,000	2.4
Year-end shares outstanding	**5,567,000**	5,410,000	2.9
Earnings (loss) per average share, continuing operations	**($0.06)**	$ 0.57	*
Earnings (loss) per average share, discontinued operations	**($1.19)**	($1.36)	*
Earnings (loss) per average share	**($1.25)**	($0.79)	*
Dividends paid per share	**$ 0.55**	$ 0.55	0.0
Operating Data			
Electric customers—year-end	**86,000**	84,000	2.4
Retail and requirements sales (MWh)	**1,955,000**	1,920,000	1.8
Other sales for resale (MWh)	**2,574,000**	2,153,000	19.6
Average revenue per kWh (cents)	**9.52**	9.47	0.5
Number of Employees—Year-End			
Green Mountain Power	**197**	196	0.5
Subsidiaries	**5**	5	0.0

*Not Meaningful

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Front cover: *Lake Champlain, Vermont; photo by Sanders Milens.*

Dear Shareholder:

By Thomas P. Salmon and Christopher L. Dutton . . 3

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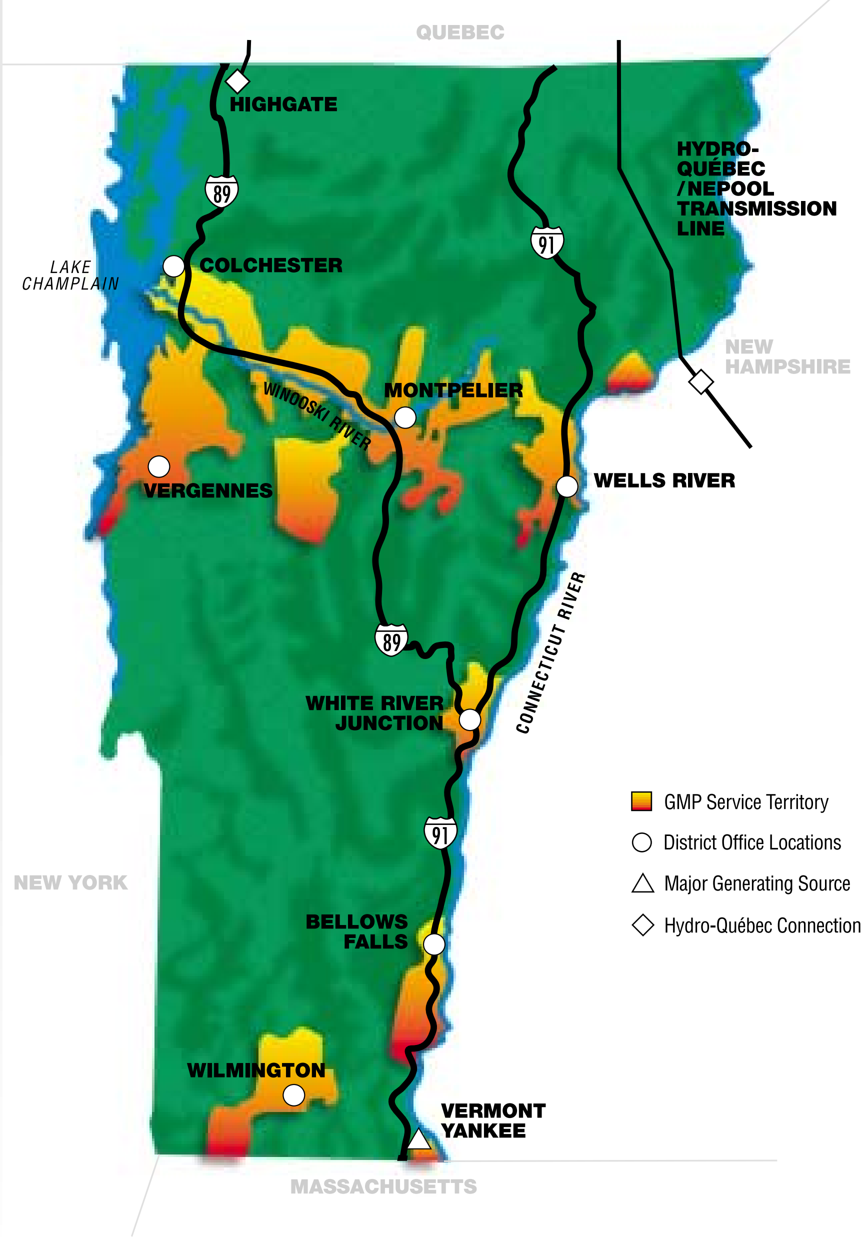
It is the policy of Green Mountain Power to provide equal employment opportunities to all qualified employees and applicants. Through its affirmative action plan and affirmative action efforts, GMP ensures that the policy is enforced.

GMP Service Territories



Dear Shareholder:

Whew! The January 23, 2001 decision by the Vermont Public Service Board approving our pending rate increase request lifted an enormous weight from the Company's shoulders.

In late 2000, we had negotiated a settlement with the Vermont Department of Public Service that allows GMP to recover the costs associated with the Hydro-Québec power supply contract. The VPSB's January 23 order approving the settlement means that shareholders' return on common equity will return to a respectable level, and should remain there for the foreseeable future.

The January 23 rate order, coupled with the results of many steps taken over the past three years to increase productivity and reduce costs, causes us to expect earnings for 2001 to be at their highest level since 1997. The greatly improved operating results should begin when we close the books on the first quarter of 2001. Moreover, GMP's retail rates should remain competitive in both the state and the region, with no increases for at least two years, and customer service will rise to new levels of effectiveness.

We believe the Company has now entered the next stage of its fundamental restructuring, which will re-establish GMP as one of New England's strongest electric utilities.

Common Stock Data

	2000	1999	1998
Net Income (Loss) Continuing Operations	**($305,000)**	$3,061,000	($2,087,000)
Net Income (Loss) Discontinued Operations	**($6,549,000)**	($7,279,000)	($2,086,000)
Net Income (Loss) Applicable To Common Stock	**($6,854,000)**	($4,218,000)	($4,173,000)
Earnings (Loss) Per Share Continuing Operations	**($0.06)**	$0.57	($0.40)
Earnings (Loss) Per Share Discontinued Operations	**($1.19)**	($1.36)	($0.40)
Earnings (Loss) Per Average Share	**($1.25)**	($0.79)	($0.80)
Weighted Average Shares Outstanding	**5,491,000**	5,361,000	5,243,000
Dividends Paid	**$0.55**	$0.55	$0.9625
Year-end Book Value	**$16.53**	$18.60	$20.15
Dividend Yield On Beginning Market Value	**7.5%**	5.2%	5.2%
Return On Average Common Equity	**(7.1%)**	(4.0%)	(3.8%)

Breakthrough On Rate Case

In November 2000, we successfully concluded months-long negotiations with the Vermont Department of Public Service, in which the parties agreed to a 3.42 percent retail rate increase. In addition, the settlement made permanent two earlier temporary increases totaling 8.5 percent. Most importantly, the settlement allowed full recovery of power costs associated with the Hydro-Québec contract. With the issuance of the VPSB order approving the settlement, GMP agreed to withdraw its Vermont Supreme Court appeal of the 1998 order disallowing a portion of the Hydro-Québec costs.

In approving the settlement substantially as negotiated with the Department, the VPSB also eliminated GMP's 20-year-old summer-winter rate

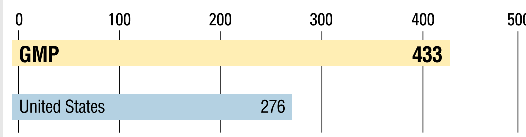
"We have solved GMP's most vexing problem, recovery of the full cost of the Hydro-Québec power contract, and the Company is poised for renewed prosperity. At the same time, we have restructured GMP from the top down, with a significantly smaller, new and nimble management team, a reduced and re-energized workforce, and a refocused strategic plan. The sails are trimmed and we're heading for open water."

— Chris Dutton,
President and Chief Executive Officer

differential, and committed the parties to the formulation of service quality standards for the first time. We strongly supported establishment of such standards, which will become the first step toward performance-based ratemaking in Vermont, a change that GMP is confident will offer future benefits for customers and shareholders.

We believe the rate order gives GMP a reasonable opportunity to earn the allowed 11.25 percent return on common equity in 2001 and 2002, years in which we have agreed not to seek rate increases unless extraordinary power supply costs exceed the level agreed upon in the rate-case settlement.

Customers Served per Employee



Investor-owned utilities only. Source: Edison Electric Institute.
Most recent data available: US 1999, GMP 2000

"GMP has strengthened old ties and built new ones with our customers, with state regulators and political leaders, and with key financial institutions. From this point on, our mission as an electric distribution company is clear, and success will be determined by our performance. The measurements will be low rates, fair return on equity, and growth of our business."

—Steve Terry
Senior Vice President, Government and Legal Relations

Furthermore, we believe the rate order sets the stage for restoration of the Company's investment-grade credit status. In February, Fitch moved the Company from a negative rating watch to a positive watch. In March, Moody's Investors Service upgraded GMP's bond rating to investment grade, citing the VPSB order.

Investors also took a fresh look at GMP after the November rate-case settlement, and by the time of final approval by the VPSB, per-share prices had risen to $16.19, up 109 percent from the November settlement.

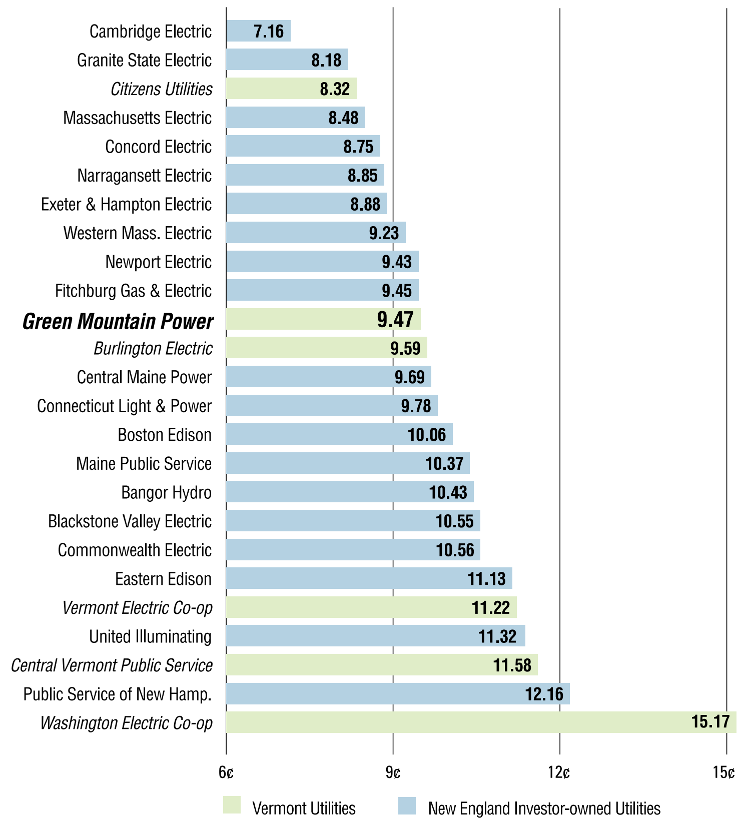
The rate-case settlement in November came at the end of a year marked by measurable progress on several financial and operational initiatives, but disappointing earnings results that reflected in part the write-down of certain costs that cleared the decks for future success. We closed 2000 with a consolidated loss of $1.25 per share of common stock. As part of the rate-case settlement that ended the crippling disallowance of Hydro-Québec power costs, we agreed to a pretax $3.2 million charge, or 35 cents per share, for disallowed regulatory litigation costs. During the year we also wrote off about $6.5 million after taxes in costs associated with the sale or write-down of remaining investments in Mountain Energy, Inc., an unregulated subsidiary that has been a drag on earnings for the past three years. The Company has now disposed of most of Mountain Energy's assets, generating $5 million in cash during 2000;

GMP's Energy Sources 2000

Hydro:	
Hydro-Québec	29.5%
NYPA	0.1
GMP Owned	3.9
	33.5
Nuclear:	
Vermont Yankee	28.8
Market Purchases:	27.3
Qualifying Facilities:	
Hydro	2.3
Ryegate (wood)	2.0
	4.3
Natural Gas:	
MMWEC	1.8
McNeil	0.4
	2.2
Oil:	
Wyman	0.6
GT&D	1.2
MMWEC	0.9
	2.7
Wood:	
McNeil	0.8
Wind:	
Searsburg	0.4
TOTAL	100.0%

New England Investor-owned Utilities and Vermont's Six Largest Utilities Retail Rates

*1999 Average Revenue per kWh**



Source: Edison Electric Institute and Vermont Department of Public Service
**Most recent data available*

GMP also in 2000 recognized the current estimated costs of winding down the subsidiary's remaining holdings.

Productivity, Customer Service Gains

GMP moved aggressively throughout the year to consolidate productivity gains from internal restructuring measures begun in 1998, and to implement technology-based improvements in customer service. Since 1998, operating costs, other than power supply and transmission costs, have been reduced by about $5 million per year. The workforce has been reduced by 50 percent, from 392 employees in 1991 to 195 at the end of 2000. During that decade, the number of customers grew by more than 9.7 percent. We believe that GMP, with a ratio of one employee for every 433 customers, operates more efficiently than any major electric utility in the nation, including those that serve more densely populated areas. Nationally, the average ratio of employees to customers for investor-owned electric utilities is one employee for every 276 customers.

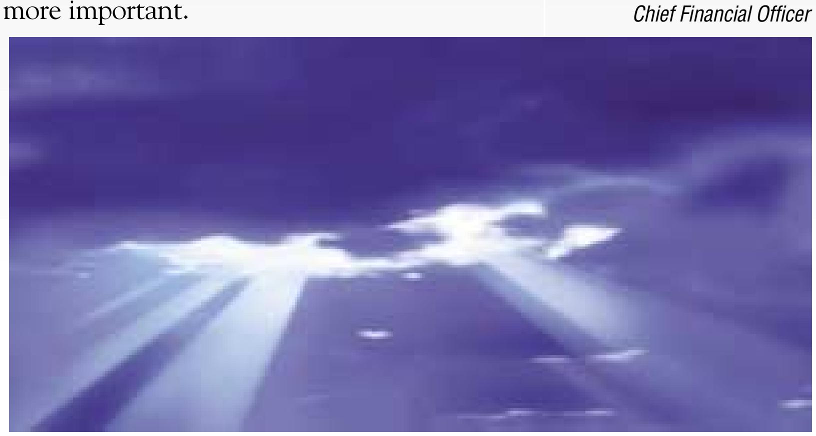
At the same time, we have maintained a customer satisfaction rating of 85 percent and in 2000 we achieved strong gains in key customer service and reliability measurements. We have cut significantly the amount of time customers wait on the phone. Meanwhile, we have reduced the number of outages to an average of less than one per year per customer.

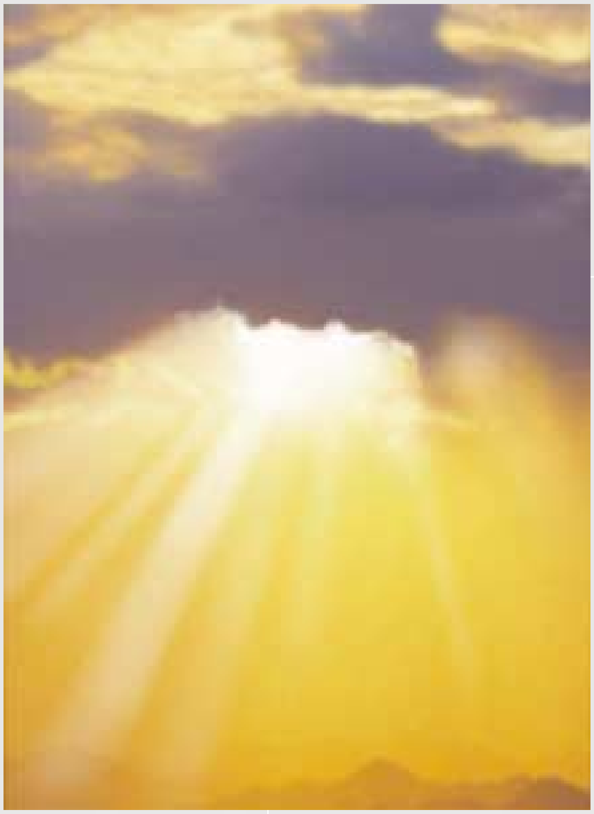
We are pleased with the results of our efforts to increase productivity, but over the long term we are certain that our parallel campaign to improve customers' service will be even more important.

As part of the rate-case settlement, GMP and regulators agreed to customer care and reliability performance standards. We will meet those standards, but for GMP they will be only a beginning. Over

"We had known for some time what our key problems were — inadequate revenue and power supply cost volatility. We believed we knew how to fix them, and we took those actions. But the proof, as always, could come only from the marketplace, from the credit rating agencies, from the lenders, and from equity investors. The response from these scorekeepers after the rate-case settlement was quick, powerful and gratifying."

— Nancy Rowden Brock
Vice President,
Chief Financial Officer





time, we intend to establish a performance record that will become the benchmark by which other electric utilities are measured.

Furthermore, GMP's retail rates are below the state and the regional averages, and our ranking will improve over the next few years as other utilities are forced to enact rate hikes that we believe we can avoid. Despite our financial challenges, GMP has kept the rate of price increases below the increase of the consumer price index and we expect to continue beating that index.

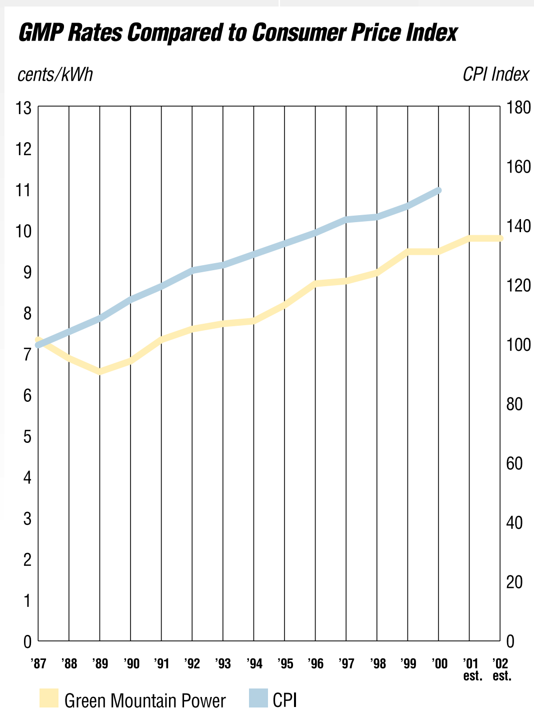
Increasingly, however, utility customers rank quality of service as their most important concern. Here, we believe, is where GMP can establish and maintain a powerful and lasting competitive advantage. There are three essential components to our plan for providing unexcelled service, all based on technology:

"The twenty-first century produc–tivity systems we need to run our business are being installed. The technology has been designed and implemented, the workforce has been trained and redeployed, and the performance benchmarks have been laid down. Our job now is execution."

—Mary Powell
Senior Vice President, Customer and Organizational Development

• **Distribution system upgrades.** In 2000, GMP increased capital spending for these improvements by 33 percent over 1999 levels, with further increases scheduled under the rate case settlement. The network of wires, poles, switches, transformers and substations is the vital core of our business. The basic function for GMP has always been, and continues to be, delivering electric power to homes and businesses. Our operating strategy is as simple as this: If we perform this distribution function well, we will win; if the distribution system fails, then we have lost.

• **Connection to customers.** Technology has radically changed this part of our business, and we have vigorously participated in this revolution. GMP now has a single, highly efficient call center. We have improved our billing system; we have implemented tough performance standards for meter reading; and we have greatly reduced response time in the call center. With a single telephone call, our customers can get up-to-the-minute information about nearly everything relating to their electric service, from how much their bill is to how much energy they're using, and if their lights flicker they can find out immediately whether there are any problems on their portion of our system. And, of course, they can get all that information and more by clicking into our on-line web service. Even with only early results to measure, it is clear that the technology-based changes have put customers and GMP in



Power Supply Costs By Source

Source	2000 Cents per kWh
Average all sources	6.0
GMP hydro	3.3
Nuclear	3.9
Market purchases	4.5
Oil and gas	6.0
Hydro-Québec	6.8
Wind	7.0
Qualifying facilities	11.2

closer contact with each other, and that proximity translates into better, faster service. We also have established goals for these tasks that we do not believe will be exceeded in our industry, and we have built-in measuring systems to mark our progress in hitting the targets.

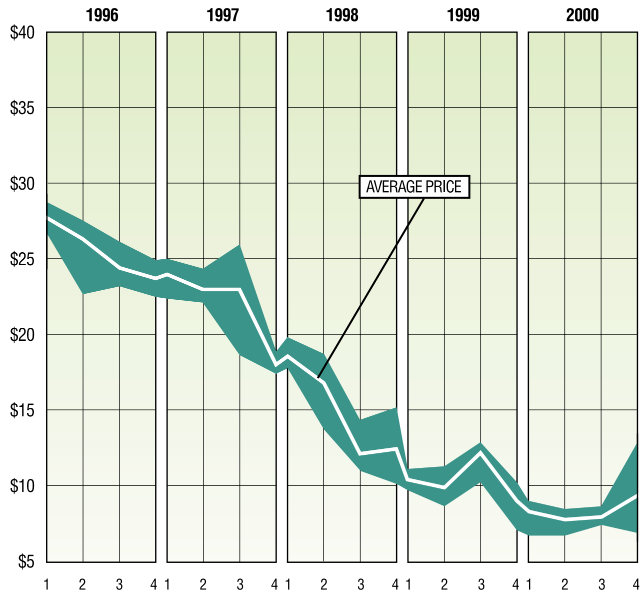
• **Reliability.** This customer value has two broad components: the number of outages and the amount of time a customer or business is off-line. Again, technology has made possible enormous improvements in both areas. GMP has 151,361 poles; 26,425 transformers; 130 distribution circuits; 38 transmission circuits; and countless switches, insulators and other hardware—all connected through 4,723 miles of wires. Technology now allows us to map and monitor the individual parts of this maze with accuracy never before possible. A new global positioning system uses satellites to pinpoint the location of every piece of the delivery system, and a global information system uses the same database to map and record information about each component. Often, especially in rural areas, the most time-consuming task in restoring power is finding the problem. This information technology will help improve our response time because we will have better information about exactly where the problems are. It will also shorten the time required for repairs because our crews will be better prepared before they arrive at a site, since the new system can tell them exactly the size of and the nature of the equipment on each pole we own and maintain. In addition, we will always be working from real-time data, since our computer-generated maps will be updated at the time of construction, without a six-month to two-year lag.

The improvements in customer service have been great and they will become even more obvious with time, but they have not been easy or painless. Change is always unsettling, of course, and for GMP change has become our daily companion. Indeed, in early 2001 some of the service-enhancing changes were a significant factor in the Company's first-ever union strike. About half of the workforce, represented by Local 300 of the International Brotherhood of Electrical Workers, left the contract bargaining table and set up picket lines. The issues that sent them off the job were not wages or benefits, but rather proposals that would alter work rules to improve response time to customers during outages. The strike lasted 22 days without incident in electrical service, and ended with union acceptance of the Company's improved final offer, which included the service enhancements. The new contract will be in

"Change has been the watchword for GMP during these past few years. One key business proposition that has not changed, however, is our rock-solid belief that the Company's most important currency is service reliability. We believe our customers right now enjoy the highest reliability ever achieved, and that technology-based improvements now under way will bring a level of service not possible at any earlier time."

— Walter Oakes
Vice President, Field Operations

Quarterly Stock Market Price Data



2000 ending stock price was $12.50.

Green Mountain Power Corporation common stock is traded on the New York Stock Exchange (NYSE symbol: GMP). This chart shows the high and low closing prices for the Company's common stock for each quarter from 1996 through 2000, as reported by the New York Stock Exchange. The number of registered shareholders of common stock as of December 29, 2000 was 6,169.

		Stock Price High	Stock Price Low	Dividend Declared
2000	First Quarter	$ 8.9375	$ 6.813	13.75¢
	Second Quarter	8.4375	6.75	13.75
	Third Quarter	8.69	7.50	13.75
	Fourth Quarter	12.81	6.88	13.75
1999	First Quarter	$11.1875	$ 9.75	13.75¢
	Second Quarter	11.3125	8.6875	13.75
	Third Quarter	14.00	10.25	13.75
	Fourth Quarter	10.25	7.125	13.75

place for three years.

GMP entered 2001 with as much security in its power supply as a utility can expect to obtain in the current volatile energy market. Both the supply and the price of energy we deliver to customers are largely fixed by long-term contracts, limiting our exposure to uncertainties caused by fossil-fuel costs. With the January 23 rate order, the cost of the long-term contract with Hydro-Quebec is now fully included in our retail rates.

We have contracted with Morgan Stanley to manage most of GMP's other power supply needs, mitigating the risk from the sharply fluctuating prices in the wholesale power markets. In 2000, the Morgan Stanley arrangement saved us more than $4 million.

GMP's power supply costs are now below the average in New England, and we have reason for optimism that their trajectory relative to the region will continue downward. Our cost for the Hydro-Québec contract, which accounts for 30 percent of the Company's total, is about the same as the current market price for power in New England. The average cost of production from generation wholly owned by the Company is below the market price, and the price of power from Vermont Yankee, which supplies 29 percent of GMP's load, is two-thirds of the cost of market power.

The eventual fate of Vermont Yankee remains uncertain because every time we think a sale is imminent, another suitor comes along with a higher offer. State regulators in February 2001 turned down an offer from AmerGen Energy Company to purchase the plant because interest from other parties indicated that the AmerGen offer did not reflect the fair market value of Vermont Yankee. The owners of the plant are now considering whether an auction would indeed be the best way to capture the value of the plant.

Whatever the outcome of the possible sale of the nuclear plant, we expect that GMP will continue to receive its historic portion of the output of Vermont Yankee through 2012, when its license expires.

Vermont remains the only one of the six New England states not moving toward retail competition in electricity, and neither the Governor nor the Legislature seems interested at this time in trying again to pass restructuring legislation. We continue to believe that retail competition will and should come to Vermont eventually, but only if the hard lessons of the California experience are learned and restructuring is accomplished on a fair and efficient basis.

In the meantime, with our own power supply problems now largely behind us, at least for the next few years, GMP can concentrate on our distribution work and on earning the allowed rate of return for shareholders, a very feasible target. That's a position we have eagerly sought for several years now, a period in which we were often reminded of this dour Scottish proverb: "A day to come seems longer than a year that's gone."

That day has finally arrived, though, and now we intend to be guided by a more American admonition: "Make the most of what you've got."

And here's a summary of what we have: Renewed confidence from the financial community, as reflected by lenders, credit-rating agencies, and investors. A new level of understanding and cooperation between the Company and Vermont regulators. A heightened level of acceptance among our employees for GMP's lean, efficiency-driven operations plan. Finally, a marketing strategy based on technology and a relentless commitment to identifying and delivering the electric service that customers want in the digital age.

Thomas P. Salmon
Chairman

Christopher L. Dutton
President and Chief Executive Officer

March 10, 2001

Board of Directors

Thomas P. Salmon, 68, elected 1978, Chairman of the Board, GMP; retired President of the University of Vermont. Of Counsel, Salmon & Nostrand, Attorneys; Former Governor of Vermont; Rockingham, Vermont.

Nordahl L. Brue, 56, elected 1992, Chairman and Chief Executive Officer of Bruegger's Corporation; Principal, Champlain Management Services, Inc.; Burlington, Vermont.

William H. Bruett, 57, elected 1986, Senior Vice President, Group Product Manager of PaineWebber, Inc., Director of PaineWebber Trust Co. and Chairman of PaineWebber International Bank Ltd., London; Weehawken, New Jersey.

Merrill O. Burns, 54, elected 1988, Group Executive, MarchFirst (Internet Professional Services); San Francisco, California.

Lorraine E. Chickering, 50, elected 1994, former President of Public Communications of Bell Atlantic Corporation; Silver Springs, Maryland.

John V. Cleary, 72, elected 1980, retired President and Chief Executive Officer, GMP; Boynton Beach, Florida.

David R. Coates, 63, elected 1999, retired Partner, KPMG Peat Marwick; Burlington, Vermont.

Christopher L. Dutton, 52, elected 1997, President, Chief Executive Officer and Chairman of the Executive Committee of GMP; Colchester, Vermont.

Euclid A. Irving, 48, elected 1993, Partner, Paul, Hastings, Janofsky & Walker, LLP, Attorneys; New York, New York.

Martin L. Johnson Retires from GMP Board

Martin L. Johnson, who served Green Mountain Power Corporation with great distinction as a member of the Board of Directors for 10 years, has retired from the Board. He is 73. His position on the Board will not be filled at this time.

"Martin Johnson was admired and respected for his environmental awareness and skills as an engineer, scientist and advocate. We will miss his insight and humor, and we certainly wish him the best," said Board Chairman Thomas P. Salmon.

Mr. Johnson was elected to the GMP Board in 1991. He lives in Marshfield, Vermont.

Board of Directors Committees

Audit Committee
Euclid A. Irving, Chair
William H. Bruett
Merrill O. Burns
David R. Coates

Compensation Committee
Merrill O. Burns, Chair
Lorraine E. Chickering
John V. Cleary
David R. Coates
Euclid A. Irving

Executive Committee
Christopher L. Dutton, Chair
Nordahl L. Brue
David R. Coates
Thomas P. Salmon

Governance Committee
William H. Bruett, Chair
Nordahl L. Brue
Lorraine E. Chickering
John V. Cleary
Thomas P. Salmon

Officers

Nancy Rowden Brock
Vice President,
Chief Financial Officer, Treasurer and Corporate Secretary

Christopher L. Dutton
President and
Chief Executive Officer

Robert J. Griffin
Controller

Walter S. Oakes
Vice President,
Field Operations

Mary G. Powell
Senior Vice President,
Customer and Organizational Development

Stephen C. Terry
Senior Vice President,
Corporate and Legal Affairs

Subsidiary

Jonathan H. Winer
President, Mountain Energy, Inc.

In this section, we explain the general financial condition and the results of operations for Green Mountain Power Corporation (the "Company") and its subsidiaries. This explanation includes:

- factors that affect our business;
- our earnings and costs in the periods presented and why they changed between periods;
- the source of our earnings;
- our expenditures for capital projects and what we expect they will be in the future;
- where we expect to get cash for future capital expenditures; and
- how all of the above affects our overall financial condition.

There are statements in this section that contain projections or estimates and that are considered to be forward-looking as defined by the Securities and Exchange Commission. In these statements, you may find words such as believes, expects, plans, or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons the results may be different are discussed under "Future Outlook", "Transmission Issues", "Environmental Matters", "Rates" and "Liquidity and Capital Resources" in this section, and include:

- regulatory and judicial decisions or legislation;
- weather;
- energy supply and demand and pricing;
- contractual commitments;
- availability, terms, and use of capital;
- general economic and business environment;
- nuclear and environmental issues; and
- industry restructuring and cost recovery (including stranded costs).

These forward-looking statements represent our estimates and assumptions only as of the date of this report.

Earnings Summary

On January 23, 2001, the Vermont Public Service Board ("VPSB") issued an order (the "Settlement Order") approving a settlement between the Company and the Vermont Department of Public Service (the "Department") that grants the Company an immediate 3.42 percent rate increase, and allows full recovery of power supply costs under the Hydro-Québec Vermont Joint Owners ("VJO") contract. The Settlement Order paves the way for restoration of the Company's investment grade status (See "Retail Rate Cases" and "Liquidity and Capital Resources" in this section) and gives the Company an opportunity to earn its allowed rate of return during 2001, or approximately $1.96 per share. During 2000, the Company lost $1.25 per share of common stock, compared with a loss per share of $0.79 in 1999 and a loss per share of $0.80 in 1998. The 2000 loss represents a negative return on average common equity of 7.1 percent. The return on average common equity was negative 4.0 percent in 1999 and negative 3.8 percent in 1998. The loss from continuing operations was $0.06 per share in 2000, compared with earnings of $0.57 per share in 1999 and a loss of $0.40 in 1998. Certain subsidiary operations, classified as discontinued in 1999, lost $1.19 per share in 2000, compared with a loss of $1.36 per share in 1999 and a loss of $0.40 per share in 1998.

The consolidated loss in 2000 was greater than the prior year consolidated loss as a result of the VPSB Settlement Order that disallowed recovery of $3.2 million or $0.35 per share in regulatory litigation costs and from higher power supply costs that were not recovered in rates. Power supply expense increased $30.2 million in 2000, outpacing revenue growth of $26.3 million and reductions in depreciation and amortization expense of $0.9 million.

The 1999 improvement in results from continuing operations was primarily due to three factors:

- retail operating revenues increased by $15.1 million, reflecting a 5.5 percent temporary rate increase that went into effect on December 15, 1998, and a 3.9 percent increase in sales to commercial and industrial customers in 1999;
- operating costs were $3.7 million lower in 1999 due to the Company's termination of its corporate headquarters lease, reduced costs associated with the Company's headquarters facilities and lower payroll expense reflecting mid-year reductions in the number of employees; and
- results for 1998 reflected pretax charges of $9.8 million in disallowed Hydro-Québec power costs for both 1998 and 1999, compared to disallowed power costs of $7.5 million for 2000 recorded in 1999.

The 1999 earnings improvement was partially offset by:

- a $4.3 million increase in the capacity costs in 1999 associated with our long-term Hydro-Québec power supply contract;
- an increase in the costs of short-term power following the deregulation of energy markets in New England, as well as an increase in our costs to serve increased local loads and an increase of approximately $5.4 million to supply power to meet contractual obligations under the Company's December 1997 sell-back agreement with Hydro-Québec; and
- a $1.9 million increase in capacity costs associated with a contract with Vermont Yankee Nuclear Power Corporation ("Vermont Yankee").

The Company's discontinued operations lost $1.19 in 2000 compared with a loss of $1.36 in 1999. During 1999, the Company discontinued operations of Mountain Energy, Inc. ("MEI"), a subsidiary of the Company that invests in wastewater, energy efficiency and generation businesses. The loss in 2000 reflects the sale of most of MEI's remaining energy assets and the current estimated costs of winding down MEI's wastewater businesses. During January 2001, MEI changed its name to Northern Water Resources, Inc. ("NWR").

Future Outlook

Competition and Restructuring—The electric utility business is experiencing rapid and substantial changes. These changes are the result of the following trends:

- disparity in electric rates, transmission, and generating capacity among and within various regions of the country;
- improvements in generation efficiency;
- increasing demand for customer choice; and
- new regulations and legislation intended to foster competition, also known as restructuring.

Electric utilities historically have had exclusive franchises for the retail sale of electricity in specified service territories. As a result, competition for retail customers has been limited to:

- competition with alternative fuel suppliers, primarily for heating and cooling;
- competition with customer-owned generation; and
- direct competition among electric utilities to attract major new facilities to their service territories.

These competitive pressures have led the Company and other utilities to offer, from time to time, special discounts or service packages to certain large customers.

In certain states across the country, including all the New England states except Vermont, legislation has been enacted to allow retail customers to choose their electricity suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems (also known as retail wheeling). Increased pressure in the electric utility industry may restrict the Company's ability to charge energy prices sufficient to recover embedded costs, such as the cost of purchased power obligations or of generation facilities owned by the Company. The amount by which such costs might exceed market prices is commonly referred to as stranded costs.

Regulatory and legislative authorities at the federal level and in some states, including Vermont where legislation has not been enacted, are considering whether, when and how to facilitate competition for electricity sales at the wholesale and retail levels. Recent difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards deregulation in Vermont. However, in the future, the Vermont General Assembly through legislation, or the VPSB through a subsequent report, action or proceeding, may allow customers to choose their electric supplier. If this happens without providing for recovery of a significant portion of the costs associated with our power supply obligations and other costs of providing vertically integrated service, the Company's franchise, including our operating results, cash flows and ability to pay dividends at the current level, would be adversely affected.

Risk Factors—The major risk factors for the Company arising from electric industry restructuring, including risks pertaining to the recovery of stranded costs, are:

- regulatory and legal decisions
- cost and amount of default service responsibility;
- the market price of power; and
- the amount of market share retained by the Company.

There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered. If laws are enacted or regulatory decisions are made that do not offer an adequate opportunity to recover stranded costs, we believe we have compelling legal arguments to challenge such laws or decisions.

The largest category of our potential stranded costs is future costs under long-term power purchase contracts, which, based on current forecasts, are above-market. The magnitude of our stranded costs is largely dependent upon the future market price of power. We have discussed various market price scenarios with interested parties for the purpose of identifying stranded costs. Preliminary market price assumptions, which are likely to change, have resulted in estimates of the Company's stranded costs of between $74 million and $162 million. We intend to aggressively pursue mitigation efforts in order to minimize the amount and maximize the recovery of these costs.

If retail competition is implemented in Vermont, we cannot predict what the impact would be on the Company's revenues from electricity sales. Historically, electric utility rates have been based on a utility's cost of service. As a result, electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards Number 71 ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates. The Company has established approximately $47.5 million of net regulatory assets and liabilities under SFAS 71.

The Company currently complies with the provisions of SFAS 71. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact would be an extraordinary, non-cash charge to operations of an amount that would be material. Factors that could give rise to the discontinuance of SFAS 71 include:

- deregulation;
- a change in the regulator's approach to setting rates from cost-based regulation to another form of regulation;
- increasing competition that limits our ability to sell utility services or products at rates that will recover costs; and
- regulatory actions that limit rate relief to a level insufficient to recover costs.

Under Statement of Financial Accounting Standards Number 5 ("SFAS 5"), Accounting for Contingencies, the enactment of restructuring legislation or issuance of a regulatory order containing provisions that do not allow for the recovery of above-market power costs would require the Company to estimate and record losses immediately, on an undiscounted basis, for any above-market power purchase contracts and other costs which are probable of not being recoverable from customers, to the extent that those costs are estimable.

We are unable to predict what form future legislation, if passed, or an order if issued, will take, and we cannot predict if or to what extent SFAS 71 will continue to be applicable in the future. In addition, members of the staff of the Securities and Exchange Commission have raised questions concerning the continued applicability of SFAS 71 to certain other electric utilities facing restructuring.

We cannot predict whether restructuring legislation enacted by the Vermont General Assembly or any subsequent report or actions of, or proceedings before, the VPSB or the Vermont General Assembly would have a material adverse effect on our operations, financial condition or credit ratings. The failure to recover a significant portion of our purchased power costs, or to retain and attract customers in a competitive environment, would likely have a material adverse effect on our business, including our operating results, cash flows and ability to pay dividends at current levels.

Inherent in our market sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices. Restructuring of the wholesale market for electricity has brought increased price volatility to power supply markets.

The price of electricity is subject to fluctuations resulting from changes in supply and demand. To reduce price risk caused by these market fluctuations, we have established a policy to hedge (through the utilization of derivatives) our supply and related purchase and sales commitments, as well as our anticipated purchase and sales. Because the commodities covered by these derivatives are substantially the same commodities that the Company buys and sells in the physical market, no special correlation studies other than monitoring the degree of convergence between the derivative and cash markets, are deemed necessary. Changes in market value of derivatives have a high correlation to the price changes of the hedged commodities.

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. Our daily net commodity position consists of purchased electric capacity. The table below presents market risk, estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in prices. Actual results may differ materially from the table.

	At December 31, 2000	
	Fair Value	Market Risk
	(In thousands)	
Highest long position	$173,741	$17,374
Highest short position	$201,608	$20,161
Average position (short)	$ 27,867	$ 2,787

Risk factors associated with the discontinuation of MEI operations include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment provided by Micronair, LLC, a wholly owned subsidiary of MEI, have commenced or threatened litigation against Micronair. The ultimate loss remains subject to the disposition of remaining MEI assets and liabilities, and could exceed the amounts recorded.

Unregulated Businesses

In 2000, we significantly reduced our investment in unregulated businesses, continuing the process we began in June 1999, when we decided to sell or otherwise dispose of the assets of MEI, and report its results as loss from operations of a discontinued segment. MEI, which invested in energy generation, energy efficiency and waste water treatment projects, lost $6.5 million in 2000, compared with a loss of $7.3 million in 1999. The 2000 loss results primarily from provisions to recognize present and estimated future losses from the sale of MEI's remaining businesses, including anticipated operating losses.

Green Mountain Resources, Inc. ("GMRI") was formed in April 1996 to explore opportunities in the emerging competitive retail energy market. In 2000, GMRI earned $19,000 compared with earnings of $583,000 in 1999. GMRI's earnings in 1999 were primarily due to the sale of its remaining interest in Green Mountain Energy Resources, ending operations for this subsidiary.

The Company's unregulated rental water-heater business earned $498,000 in 2000, essentially unchanged from 1999's net income of $500,000. Both 2000 and 1999 results contributed earnings of 9 cents per share to the Company's consolidated results.

Results of Operations

Operating Revenues and MWh Sales—Operating revenues and megawatthour ("MWh") sales for the years ended 2000, 1999 and 1998 consisted of:

	Years ended December 31,		
	2000	1999	1998
	(Dollars in thousands)		
Operating Revenues:			
Retail	$188,849	$179,997	$164,855
Sales for Resale	85,428	68,305	16,529
Other	3,049	2,746	2,920
Total Operating Revenues	$277,326	$251,048	$184,304
Megawatthour Sales:			
Retail	1,947,857	1,900,188	1,839,522
Sales for Resale	2,575,657	2,172,849	543,846
Total Megawatthour Sales	4,523,514	4,073,037	2,383,368

Differences in operating revenues were due to changes in the following:

	1999 to 2000	1998 to 1999
	(In thousands)	
Retail Rates	$ 4,230	$ 9,395
Retail Sales Volume	4,622	5,747
Resales and Other Revenues	17,426	51,602
Increase in Operating Revenues	$26,278	$66,744

In 2000, total electricity sales increased 11.1 percent due principally to sales for resale executed pursuant to the Morgan Stanley Capital Group, Inc. ("MS") agreement, described in more detail below under the headings "Power Supply Expense" and "Power Contract Commitments". Total operating revenues increased $26.3 million or 10.5 percent primarily for the same reason. Total retail revenues increased $8.9 million or 4.9 percent in 2000 primarily due to:

- a 3.0 percent retail rate increase that went into effect January, 2000; and
- a 2.6 percent increase in sales of electricity to both our commercial and industrial and our residential customers resulting primarily from customer growth and load growth for our largest customer.

In 1999, total electricity sales increased 70.9 percent due principally to sales for resale executed pursuant to the MS agreement. Total operating revenues increased $66.7 million or 36.2 percent in 1999 for the same reason. Total retail revenues increased $15.1 million or 9.2 percent in 1999 primarily due to:

- a 5.5 percent retail rate increase for service rendered on or after December 15, 1998;
- a 3.9 percent increase in sales of electricity to our commercial and industrial customers resulting from customer growth and increased use of air conditioning during the spring and summer months; and
- a 3.3 percent increase in sales of electricity to residential customers, a result of customer growth and a warmer than normal summer.

International Business Machines ("IBM"), the Company's single largest customer, operates manufacturing facilities in Essex Junction, Vermont. IBM's electricity requirements for its main plant and an adjacent plant accounted for 11.2, 11.8, and 14.7 percent of the Company's total operating revenues in 2000, 1999, and 1998, respectively, and 16.5, 16.4 and 17.1 percent of the Company's retail operating revenues in 2000, 1999, and 1998, respectively. No other retail customer accounted for more than one percent of the Company's revenue in any year.

Since 1995, the Company has had agreements with IBM with respect to electricity sales above agreed-upon base-load levels. On December 8, 2000, the VPSB approved a new three-year agreement between the Company and IBM, ending December 31, 2003. The price of power for the renewal period of the agreement is above our marginal costs of providing incremental service to IBM.

Power Supply Expenses—Our inability to recover our power supply costs has been the primary reason for the poor performance of the Company's common stock over the past three years. The Settlement Order removes this obstacle by allowing the Company rate recovery of its estimated power supply costs for 2001. Furthermore, the Settlement Order allows the Company to use approximately $6.0 million in rate levelization cash flow to achieve its allowed rate of return in 2001 and 2002, and, together with the extension of our power supply agreement with MS, provides us an opportunity to recover our power supply costs in 2002 without further rate relief (See "Power Supply Commitments", "Retail Rate Cases" and "Risk Factors" in this section).

Power supply expenses constituted 79.4, 75.4, and 67.7 percent of total operating expenses for the years 2000, 1999, and 1998, respectively. Power supply expenses increased by $30.2 million or 16.5 percent in 2000 and $62.2 million or 51.4 percent in 1999. The increase in power supply expenses from 1999 to 2000 resulted from the following:

- a $20.0 million increase from power purchased for resale, primarily under a power supply agreement discussed below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a pre-defined price;
- a $7.7 million increase in energy costs arising from a power supply arrangement with Hydro-Québec, discussed below, whereby Hydro-Québec has an option to purchase energy at prices that were below market replacement costs;
- the costs to serve increased retail sales of electricity of 2.8 percent in 2000 and higher unit power supply costs; and
- a $3.6 million increase in capacity costs associated with our long-term Hydro-Québec power supply contract.

These amounts were partially offset by a reduction in 2000 of $9.7 million in losses accrued for the Hydro-Québec power cost disallowance under past regulatory rulings. Results for 1999 reflected pretax charges of $2.2 million in disallowed Hydro-Québec power costs, compared with the amortization during 2000 of accrued power expense of $7.5 million for 2000 that had been recorded in 1999. The power supply costs of Company-owned generation increased 74.8 percent or $4.2 million in 2000 due to purchases by MS under a power supply agreement discussed below and because units were dispatched for system reliability requirements due to the unavailability of certain transmission facilities. Power supply expenses increased by $62.2 million or 51.4 percent from 1998 to 1999. The increase in power supply expenses from 1998 to 1999 resulted from the following:

- a $57.0 million increase reflecting the power supply agreement discussed below, whereby we buy power from MS that is sufficient to serve pre-established load requirements at a predefined price;
- a $4.3 million increase in the capacity costs in 1999 associated with our long-term Hydro-Québec power supply contract;
- an increase in the costs of short-term power following the deregulation of wholesale energy markets in New England, as well as an increase in our costs to serve increased local loads and to supply power to meet contractual obligations under the Company's December 1997 sell-back arrangement with Hydro-Québec (net cost approximately $5.4 million); and
- a $1.9 million increase in Vermont Yankee capacity costs.

These amounts were partially offset by a reduction of $2.3 million in losses accrued for the Hydro-Québec power cost disallowance. Results for 1998 reflected pretax charges of $9.8 million in disallowed Hydro-Québec power costs for both 1998 and 1999, compared with disallowed power costs of $7.5 million for 2000 recorded in 1999.

The power supply costs of Company-owned generation decreased 13.0 percent in 1999 due to the severe 1998 ice storm in New England that caused increased usage in that year of peak generation resources to replace power that was unavailable from Hydro-Québec.

An Independent System Operator in New England ("ISO") replaced the New England Power Pool ("NEPOOL") effective May 1, 1999. The ISO works as a clearinghouse for purchasers and sellers of electricity in the new deregulated wholesale markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold.

We must purchase electricity to meet customer demand during periods of high usage and to replace energy repurchased by Hydro-Québec under an arrangement negotiated in 1997. Our costs to serve demand during periods of warmer than normal temperatures in summer months and to replace such energy repurchases by Hydro-Québec rose substantially after the wholesale power markets became deregulated, which caused much greater volatility in spot prices for electricity. The cost of securing future power supplies has also risen substantially in tandem with higher summer power supply costs. The Company cannot predict the duration or the extent to which future prices will continue to trade above historical levels of cost. If the new markets continue to experience the volatility evident during 1999 and 2000, our earnings and cash flow could be adversely impacted by a material amount.

Power Contract Commitments—On February 11, 1999, we entered into a contract with MS as a result of our power requirements solicitation in 1998. A master power purchase and sales agreement ("PPSA") defines the general contract terms under which the parties may transact. The sales under the PPSA commenced on February 12, 1999 and will terminate after all obligations under each transaction entered into by MS and the Company have been fulfilled. The PPSA has been noticed to the VPSB and filed with the Federal Energy Regulatory Commission ("FERC"). In January 2001, the PPSA was modified and extended to December 31, 2003.

The PPSA provides us with a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, we sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to us, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. We remain responsible for resource performance and availability. MS provides no coverage against major unscheduled outages. The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. We estimate that the Company saved approximately $4.8 million during 2000 over what our energy costs would have been absent the PPSA due to our avoiding significant increases in 2000 fossil fuel prices.

During 1994, we negotiated an arrangement with Hydro-Québec that reduced the cost under our 1987 contract with Hydro-Québec (the "1987 Contract") over the November 1995 through October 1999 period (the July 1994 Agreement).

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Québec over a four-year period (which has since been extended to 2001), and made a $6.5 million (in 1994 dollars) payment to Hydro-Québec in 1995. Hydro-Québec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2000 to 2015 period, if documented drought conditions exist in Québec.

During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent (or $16 million) cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Québec, the combined unit costs will be lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

Under a power supply arrangement executed in January 1996 ("9601"), we received payments from Hydro-Québec of $3.0 million in 1996 and $1.1 million in 1997. Under 9601 we are required to shift up to 40 megawatts of deliveries to an alternate transmission path, and use the associated portion of the NEPOOL/Hydro-Québec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that vary based upon conditions in effect when the purchases are made. 9601 also provides for minimum payments by the Company to Hydro-Québec for periods in which power is not purchased under the arrangement. 9601 allows Hydro-Québec to curtail deliveries of energy should it need to use certain resources to supplement available supply. Hydro-Québec did curtail deliveries in the fourth quarter of 2000. Although our level of future benefits will depend on various factors, including market prices and availability of energy from HQ, we estimate that 9601 has provided a benefit of approximately $3.0 million on a net present value basis through December 31, 2000.

Under a separate arrangement executed on December 5, 1997 ("9701"), Hydro-Québec paid $8.0 million to the Company in 1997. In return for this payment, we provided Hydro-Québec options for the purchase of power. Commencing April 1, 1998 and effective through the term of the 1987 Contract, which ends in 2015, Hydro-Québec may purchase up to 52,500 MWh ("option A") on an annual basis, at the 1987 Contract energy prices, which are substantially below current market prices. The cumulative amount of energy that may be purchased under option A shall not exceed 950,000 MWh.

Over the same period, Hydro-Québec may exercise an option to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Under option B, Hydro-Québec may purchase no more than 200,000 MWh in any year. As of December 31, 2000, Hydro-Québec had purchased or called to purchase 349,000 MWh under option B, including calls for January and February of 2001.

In 2000, Hydro-Québec exercised option A and option B, calling for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of January and February, 2001 calls, and the cost of related financial positions), which was due to higher energy replacement costs incurred by the Company. Approximately $6.6 million of the $14.0 million net 9701 costs were recovered in rates on an annual basis.

In 1999, Hydro-Québec called for deliveries to third parties at a net cost of approximately $6.3 million. Hydro-Québec's option to curtail energy deliveries pursuant to the July 1994 Agreement can be exercised in addition to these purchase options.

The VPSB, in the Settlement Order said, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 97-01 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Québec committed to the Department that it would not call any energy under option B of 9701 during 2002.

In 1999, the Company and the other Vermont Joint Owners who are parties to the Hydro-Québec contract initiated an arbitration against Hydro-Québec, pursuant to the 1987 Contract terms, to determine whether Hydro-Québec's suspension of deliveries of power to Vermont during and after the January 1998 ice storm evidenced a default by Hydro-Québec under the terms of that contract. Hydro-Québec maintains that the "force majeure" (superior or irreversible force) provision in the 1987 Contract applies, which could excuse its non-delivery of power under these circumstances. Arbitration of the dispute may lead to remedies having a material impact on our contractual obligation, including the possibility that the 1987 Contract be declared terminated or void. If arbitration results in a cash payment, it will first be applied to a regulatory asset of $4.7 million for arbitration litigation costs. The Settlement Order provides that the Company will not earn a return on these litigation costs, unless the case results in lower power supply costs for ratepayers. Hearings have concluded and a decision is expected April 2001. If the contract is declared terminated or void, the Company would have to replace a substantial amount of its power needs at terms which could materially exceed the 1987 Contract price for 2001. The Company believes that it could contract replacement power at costs below the long term costs of the 1987 Contract.

Other Operating Expenses—Other operating expenses increased $0.1 million in 2000. The increase is primarily due to a $3.2 million charge for disallowed regulatory litigation costs, ordered by the VPSB as part of the Settlement Order. The increase was offset by a $3.3 million decrease in administrative and general expense caused by the Company's reorganization efforts that reduced the size of the workforce and lowered building occupancy costs.

Other operating expenses decreased $3.7 million or 17.4 percent in 1999. The decrease resulted from:

- a $1.9 million estimated loss in 1998 to recognize the cost of terminating the Company's corporate headquarters operating lease. The facilities were sold in April 1999;
- a $1.4 million reduction in administrative and general salaries related to a workforce reduction plan;
- the elimination in 1999 of a regulatory liability of $1.2 million relating to the Company's former corporate headquarters; and
- reductions in lease expense and facility carrying costs resulting from the disposal of the former headquarters.

These savings were partially offset by increased costs of approximately $1.8 million associated with the Company's reorganization.

Transmission Expenses—Transmission expenses increased $1.5 million or 14.0 percent in 2000 primarily due to congestion charges that reflect the lack of adequate transmission or generation capacity in certain locations within New England. These charges are allocated to all ISO New England members. The Company is unable to predict the magnitude or duration of future congestion charge allocation, but amounts could be material. Transmission expenses increased $1.4 million or 15.0 percent in 1999 due to costs associated with the creation of the ISO as the clearing house for power trades in New England and due to refunds in 1998 from Central Vermont Public Service Corp. and New England Power Company.

A FERC ruling in December 2000 required ISO New England to revise its installed capability ("ICAP") deficiency charge of $0.17 per kw month to $8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, FERC stayed its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for re-hearing, which, if successful, would then require extensive refunds and surcharges." On March 6, 2001, FERC issued an Order on Rehearing in which it partly reversed itself on the ICAP charge. Although the Commission first concluded that a $8.75 charge is reasonable and that the charge would remain in place until the ISO supports an acceptable superceding proposal, the Commission then concluded that reinstating the $8.75 would have a large cost impact. As a result, the $0.17 per kw month charge was reinstated from August 1, 2000 until April 1, 2001. The Commission allowed the $8.75 charge to become effective on April 1, 2001 until the effective date of any superceding charge the Commission might accept. As a result, the Company should have no exposure to paying the difference in the two charges for the period from August 1, 2000 until April 1, 2001.

In 2000, FERC issued a separate order ("Order 2000") requiring all utilities to file plans for the formation and administration of regional transmission organizations ("RTO"). In January 2001, the Company and other Vermont transmission-owning companies filed in compliance with Order 2000. The Vermont companies support the Petition for Declaratory Order by various New England transmission-owning companies, with reservations. The Vermont companies' principal concerns relate to:

- whether a New England RTO ("NERTO") will include all non-Pool Transmission Facilities in the NERTO Tariff on a rolled in basis;
- whether Highgate and Phase I/Phase II transmission facilities will be included in the Tariff without a separate transmission levy; and,
- whether NERTO will continue the transition to a single regional transmission rate; and the percentage of equity that transmission owners may acquire in the new organization.

The Company is unable to estimate how these issues will be resolved, but the impact could be material.

Maintenance Expenses—Maintenance expenses decreased $0.1 million or 1.4 percent in 2000 due to changes in scheduled maintenance. Maintenance expenses increased $1.5 million or 29.6 percent in 1999, reflecting increased expenditures on right-of-way maintenance programs.

Depreciation and Amortization—Depreciation and amortization expenses decreased $0.9 million or 5.5 percent in 2000 due to reductions in amortization of demand side management costs that were only partially offset by increased depreciation of utility plant in service. In 1999, depreciation and amortization were at similar levels compared with that of 1998.

Income Taxes—Income tax amounts decreased for 2000 due to an increase in the Company's taxable loss. Income taxes decreased for 1999 due to a decrease in taxable income.

Other Income—Other income decreased $0.7 million in 2000 due to a $0.6 million gain on the 1999 sale of GMER. Other income increased $1.9 million in 1999, due to the 1999 gain on the sale of the Company's remaining interest in GMER discussed previously under "Unregulated Businesses", and a $0.9 million write-off in 1998 for disallowed costs at our Searsburg wind project.

Interest Charges—Interest expense increased $0.1 million or 1.0 percent in 2000 due to increases in short-term debt and rising interest rates that were partially offset by reductions in long-term debt. Interest expense decreased $0.7 million or 8.7 percent in 1999, consistent with reductions in average long-term and short-term debt outstanding during the year.

Dividends on Preferred Stock—Dividends on preferred stock decreased $141,000, or 12.2 percent in 2000 due to repurchases of preferred stock. In 1999, the dividends on preferred stock also decreased $141,000 or 10.9 percent for the same reason.

Environmental Matters

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

Pine Street Barge Canal Site—The Federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), commonly known as the "Superfund" law, generally imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. We have previously been notified by the Environmental Protection Agency ("EPA") that we are one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal site in Burlington, Vermont, where coal tar and other industrial materials were deposited.

In September 1999, we negotiated a final settlement with the United States, the State of Vermont (the "State"), and other parties to a Consent Decree that covers claims with respect to the site and implementation of the selected site cleanup remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2000, our total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $23.5 million. This includes amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently awaiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals for a more expensive remedy at the site, litigation and related costs necessary to obtain settlements with insurers and other PRPs to provide amounts required to fund the clean up ("remediation costs"), and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million over the next 33 years. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset and we believe that it is probable that we will receive future revenues to recover these costs.

Through rate cases filed in 1991, 1993, 1994, and 1995, we sought and received recovery for ongoing expenses associated with the Pine Street Barge Canal site. While reserving the right to argue in the future about the appropriateness of full rate recovery of the site-related costs, the Company and the Department, and as applicable, other parties, reached agreements in these cases that the full amount of the site-related costs reflected in those rate cases should be recovered in rates.

We proposed in our rate filing made on June 16, 1997 recovery of an additional $3.0 million in such expenditures. In an Order in that case released March 2, 1998, the VPSB suspended the amortization of expenditures associated with the Pine Street Barge Canal site pending further proceedings. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street Barge Canal site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers". The Settlement Order released January 23, 2001 did not change the status of Pine Street cost recovery.

Clean Air Act—Because we purchase most of our power supply from other utilities, we do not anticipate that we will incur any material direct cost increases as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act. Furthermore, only one of our power supply purchase contracts, which expired in early 1998, related to a generating plant that was affected by Phase I of the acid rain provisions of this legislation, which went into effect January 1, 1995.

Rates

Retail Rate Cases—On March 2, 1998, the VPSB released its Order dated February 27, 1998 in the then pending rate case (the "1997 rate case"). The VPSB authorized us to increase our rates by 3.61 percent, which gave us increased annual revenues of $5.6 million. The VPSB Order denied us the right to charge customers $5.48 million of the annual costs for power purchased under our contract with Hydro-Québec. The VPSB denied recovery of these costs for the following reasons:

- the VPSB claimed that we had acted imprudently by committing to the power contract with Hydro-Québec in August 1991 (the imprudence disallowance); and
- to the extent that the costs of power to be purchased from Hydro-Québec were higher than estimates of market prices for power during the contract term, after accounting for the imprudence disallowance, the contract power was decreed not "used and useful".

We appealed the VPSB's ruling in the 1997 rate case to the Vermont Supreme Court.

On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment (the "1998 rate case").

On November 18, 1998, by Memorandum of Understanding ("MOU"), the Company, the Department and IBM agreed to stay rate proceedings in the 1998 rate case until or after September 1, 1999, or such earlier date as the parties may later agree to or the VPSB may order. The agreement to suspend our 1998 rate case delayed the date of a final decision on the 1998 rate case to December 15, 1999, and we recognized an additional loss of $5.25 million in the last quarter of 1998 representing the effect of the continued disallowance of Hydro-Québec costs through December 15, 1999. The MOU provided for a 5.5 percent temporary retail rate increase, to produce $8.9 million in annualized additional revenue, effective with service rendered December 15, 1998. An additional surcharge was permitted, without further VPSB order, in order to produce additional revenues necessary to provide the Company with the capacity to finance 1999 Pine Street Barge Canal site expenditures. The MOU was approved by the VPSB on December 11, 1998. The MOU did not provide for any specific disallowance of power costs under our purchase power contract with Hydro-Québec. Issues respecting recovery of such power costs were preserved for future proceedings.

The stay and suspension of the 1998 rate case and the temporary rate levels agreed to in the MOU were designed to allow us to continue to provide adequate and efficient service to our customers while we sought mitigation of power supply costs.

On September 7 and December 17, 1999, the VPSB issued Orders approving two amendments to the MOU that the Company had entered into with the Department and IBM. The two amendments continued the stay of proceedings until September 1, 2000, with a final decision expected by December 31, 2000. The amendments maintained the other features of the original MOU, and the second amendment provided for a temporary rate increase of 3 percent, in addition to the previous temporary rate level, to become effective as of January 1, 2000. The Company reached a final settlement agreement with the Department in the 1998 rate case during November 2000. The final settlement agreement contains the following provisions:

- a rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases become permanent;
- rates are set at levels that recover the Company's Hydro-Québec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company over the past three years;
- the Company agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
- the Company agrees to write off approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
- seasonal rates will be eliminated in April 2001, which is expected to generate approximately $6.0 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2001, 2002 and 2003;
- the Company agrees to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making; and
- the Company agrees to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the 1997 rate case.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions. The VPSB Order requires the Company and customers to share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share. The second condition restricts Company investments in non-utility operations.

Liquidity and Capital Resources

Construction—Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. Capital expenditures over the past three years and forecasted for 2001 are as follows:

Dividend Policy—The annual dividend rate was $0.55 per share at December 31, 2000.

The Settlement Order limits the dividend rate at its current level until short-term credit facilities are replaced with long-term debt or equity financings. Retained earnings at December 31, 2001 were approximately $0.5 million. The Company anticipates substantial improvement in retained earnings during 2001, beginning with the first quarter, and believes it will be able to maintain the current dividend rate. If retained earnings were eliminated, the Company would not be able to declare a dividend under its Restated Articles of Association.

Financing and Capitalization—Internally generated funds provided approximately 59 percent of requirements for 2000, 1999 and 1998 combined. Internally generated funds, after payment of dividends, provide capital requirements for construction, sinking funds and other requirements. We anticipate that for 2001, internally generated funds will provide approximately 90 percent of total capital requirements for regulated operations.

At December 31, 2000, our capitalization consisted of 49.3 percent common equity, 43.8 percent long-term debt and 6.9 percent preferred equity.

On June 21, 2000, we renewed a $15.0 million revolving credit agreement with Fleet National Bank and Citizens Bank of Massachusetts (the "Fleet Agreement"). The Fleet Agreement is for a period of 364 days and will expire on June 20, 2001. At December 31, 2000, there was $0.5 million outstanding on the Fleet Agreement. The Fleet Agreement is secured by granting the banks a second priority mortgage, lien and security interest in the collateral pledged under the Company's first mortgage bond indenture.

On September 20, 2000, we established a $15.0 million revolving credit agreement with KeyBank National Association ("KeyBank"). The agreement will expire on September 19, 2001. Pursuant to a one-year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE upon

Capital Expenditures

	Generation	Transmission	Distribution	Conservation	Other*	Total Net Expenditures
	(Dollars in thousands and net of AFUDC and customer advances for construction)					
Actual:						
1998	$ 543	$ 751	$6,063	$1,244	$4,568	$13,169
1999	210	144	5,930	1,943	9,039	17,266
2000	2,195	931	7,169	**	3,955	14,250
Forecasted:						
2001	$2,830	$2,060	$8,540	**	$2,320	$15,750

*Other includes $6.1 million in 1999, $1.3 million in 2000, and $1.9 million in 2001 for the Pine Street Barge Canal site.
**A statewide Energy Efficiency Utility set up by the VPSB in 1999 manages all energy efficiency programs, receiving funds the Company bills to its customers as a separate charge.

request after September 2001. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank, pledged by the Company to secure the repayment of the Keybank revolving credit facility. At December 31, 2000, there was $15.0 million outstanding on the KeyBank line of credit.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2001. The Settlement Order will likely permit restoration of the Company's investment grade debt ratings, allowing arrangement of such financing as the Company needs during 2001.

The credit ratings of the Company's securities are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BB+	Baa2	BBB
Unsecured medium-term debt	BB–	—	—
Preferred stock	B+	baa3	BB

On March 5, 2001, Moody's Investors Service upgraded the Company's first mortgage bond rating to Baa2 from Ba1, and upgraded the Company's preferred stock rating to baa3 from ba3. The rating action reflected Moody's earnings and cash flow expectations following the Settlement Order.

On August 25, 2000, Fitch (formerly Duff & Phelps) downgraded the credit ratings of the Company to below investment grade and maintained the ratings on Rating Watch-Negative. Since the Settlement Order, Fitch and Standard & Poor's have favorably changed their outlook relative to the ratings direction for the Company, moving us from Rating Watch-Negative and Credit Watch-Negative to Rating Watch-Positive and Credit Watch-Developing, respectively.

Nuclear Decommissioning—The staff of the SEC has questioned certain current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating units in financial statements. In response to these questions, the Financial Accounting Standards Board had agreed to review the accounting for closure and removal costs, including decommissioning. We do not believe that changes in such accounting, if required, would have an adverse effect on the results of operations due to our current and future ability to recover decommissioning costs through rates.

Effects of Inflation—Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This accounting provides reasonable financial statements but does not always take inflation into consideration. As rate recovery is based on these historical costs and known and measurable changes, the Company is able to receive some rate relief for inflation. It does not receive immediate rate recovery relating to fixed costs associated with Company assets. Such fixed costs are recovered based on historic figures. Any effects of inflation on plant costs are generally offset by the fact that these assets are financed through long-term debt.

Consolidated Statements of Income

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2000	1999	1998
	(In thousands, except amounts per share)		
Operating Revenues	**$277,326**	$251,048	$184,304
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**34,813**	34,987	32,910
Company-owned generation	**9,756**	5,582	6,412
Purchases from others	**168,947**	142,699	81,706
Other operating	**17,644**	17,582	21,291
Transmission	**12,258**	10,800	9,389
Maintenance	**6,633**	6,728	5,190
Depreciation and amortization	**15,304**	16,187	16,059
Taxes other than income	**7,402**	7,295	7,242
Income taxes	**(691)**	1,242	(1,367)
Total operating expenses	**272,066**	243,102	178,832
Operating income	**5,260**	7,946	5,472
Other Income			
Equity in earnings of affiliates and non-utility operations	**2,495**	2,919	2,058
Allowance for equity funds used during construction	**284**	134	104
Other income (deductions), net	**(73)**	400	(549)
Total other income (deductions)	**2,706**	3,453	1,613
Income before interest charges	**7,966**	11,399	7,085
Interest Charges			
Long-term debt	**6,499**	6,716	6,991
Other	**986**	558	1,016
Allowance for borrowed funds used during construction	**(228)**	(91)	(131)
Total interest charges	**7,257**	7,183	7,876
Income (loss) before preferred dividends and discontinued operations	**709**	4,216	(791)
Dividends on preferred stock	**1,014**	1,155	1,296
Income (loss) from continuing operations	**(305)**	3,061	(2,087)
Net income (loss) from discontinued segment operations	**—**	(603)	(2,086)
Loss on disposal, including provisions for operating losses during phaseout period	**(6,549)**	(6,676)	—
Net Income (Loss) Applicable to Common Stock	**($ 6,854)**	($ 4,218)	($ 4,173)
Common Stock Data			
Basic and diluted earnings (loss) per share from discontinued operations	**($ 1.19)**	($ 1.36)	($ 0.40)
Basic and diluted earnings (loss) per share from continuing operations	**(0.06)**	0.57	(0.40)
Basic and diluted earnings (loss) per share	**($ 1.25)**	($ 0.79)	($ 0.80)
Cash dividends declared per share	**$ 0.55**	$ 0.55	$ 0.96
Weighted average shares outstanding	**5,491**	5,361	5,243

Consolidated Statements of Retained Earnings

	2000	1999	1998
Balance—beginning of period	**$ 10,344**	$ 17,508	$ 26,717
Net Income (loss)	**(5,840)**	(3,063)	(2,877)
	4,504	14,445	23,840
Cash Dividends—redeemable cumulative preferred stock	**1,014**	1,155	1,296
Cash Dividends—common stock	**2,997**	2,946	5,036
	4,011	4,101	6,332
Balance—end of period	**$ 493**	$ 10,344	$ 17,508

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

GREEN MOUNTAIN POWER CORPORATION • For the Twelve Months Ended December 31

	2000	1999	1998
		(In thousands)	
Operating Activities:			
Net Income (Loss)	($ 5,840)	($3,063)	($ 2,877)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	15,304	16,187	16,059
Dividends from associated companies less equity income	(26)	169	812
Allowance for funds used during construction	(512)	(224)	(235)
Amortization of purchased power costs	5,575	5,725	6,405
Deferred income taxes	443	1,812	(112)
Loss on operations of discontinued segment	6,549	6,676	—
Deferred purchased power costs	(6,692)	(6,590)	(7,830)
Accrued purchased power contract option call	8,276	—	—
Deferred arbitration costs	(3,184)	(1,684)	—
Amortization of investment tax credits	(282)	(282)	(282)
Provision for chargeoff of deferred regulatory asset	3,229	—	—
Environmental and conservation expenditures	(2,073)	(8,048)	1,177
Changes in:			
Accounts receivable	(3,862)	474	(1,611)
Accrued utility revenues	(125)	(358)	(105)
Fuel, materials and supplies	(766)	(150)	122
Prepayments and other current assets	(165)	4,009	(983)
Accounts payable	3,004	665	(1,893)
Accrued income taxes payable and receivable	(372)	(1,611)	(2,473)
Other current liabilities	(7,341)	1,722	3,229
Other	(180)	(324)	536
Net cash provided by continuing operations	10,959	15,105	9,939
Net change in discontinued segment	245	(138)	—
Net cash provided by operating activities	11,204	14,967	9,939
Investing Activities:			
Construction expenditures	(13,853)	(9,174)	(10,900)
Proceeds from sale of subsidiaries	6,000	—	11,500
Investment in non-utility property	(187)	(190)	(1,442)
Net cash provided by (used in) investing activities	(8,040)	(9,364)	(842)
Financing Activities:			
Issuance of common stock	1,250	1,054	1,587
Investment in Certificate of Deposit, pledged for revolver	(15,437)	—	—
Energy East obligation	15,419	—	—
Short-term debt, net	7,600	900	4,384
Cash dividends	(4,011)	(4,101)	(6,332)
Reduction in preferred stock	(1,640)	(1,650)	(1,650)
Reduction in long-term debt	(6,700)	(1,700)	(6,767)
Net cash provided by (used in) financing activities	(3,519)	(5,497)	(8,778)
Net increase (decrease) in cash and cash equivalents	(355)	106	319
Cash and cash equivalents at beginning of period	696	590	271
Cash and Cash Equivalents at End of Period	$ 341	$ 696	$ 590
Supplemental Disclosure of Cash Flow Information:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	$ 7,185	$ 7,034	$ 7,857
Income taxes, net	1,191	997	2,285

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Capitalization Data

GREEN MOUNTAIN POWER CORPORATION • December 31

CAPITAL STOCK	Authorized	Issued and Outstanding 2000	1999	2000 (In thousands)	1999
Common Stock,					
$3.33⅓ par value	10,000,000	**5,582,552**	5,425,571	**$18,608**	$18,085

	Authorized	Issued	Outstanding 2000	1999	2000 (In thousands)	1999
Redeemable Cumulative Preferred Stock,						
$100 par value						
4.75%, Class B,						
redeemable at $101 per share	15,000	15,000	**1,450**	1,800	**$ 145**	$ 180
7%, Class C,						
redeemable at $101 per share	15,000	15,000	**3,300**	3,750	**330**	375
9.375%, Class D, Series 1,						
redeemable at $101 per share	40,000	40,000	**3,200**	4,800	**320**	480
8.625% Class D, Series 3,						
redeemable at $100.916 per share	70,000	70,000	**—**	14,000	**—**	14,000
7.32%, Class E, Series 1	200,000	120,000	**120,000**	120,000	**12,000**	12,000
Total Preferred Stock					**$12,795**	$14,435

LONG-TERM DEBT (Note E)	2000 (In thousands)	1999
First Mortgage Bonds		
5.71% Series due 2000	**$ —**	$ 5,000
6.21% Series due 2001	**8,000**	8,000
6.29% Series due 2002	**8,000**	8,000
6.41% Series due 2003	**8,000**	8,000
10.0% Series due 2004—Cash sinking fund, $1,700,000 annually	**6,800**	8,500
7.05% Series due 2006	**4,000**	4,000
7.18% Series due 2006	**10,000**	10,000
6.7% Series due 2018	**15,000**	15,000
9.64% Series due 2020	**9,000**	9,000
8.65% Series due 2022—Cash sinking fund, commences 2012	**13,000**	13,000
Total Long-term Debt Outstanding	**81,800**	88,500
Less Current Maturities (due within one year)	**9,700**	6,700
Total Long-term Debt, Net	**$72,100**	$81,800

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

ASSETS	2000	1999
	(In thousands)	
Utility Plant		
Utility plant, at original cost	**$291,107**	$283,917
Less accumulated depreciation	**110,273**	102,854
Net utility plant	**180,834**	181,063
Property under capital lease	**6,449**	7,038
Construction work in progress	**7,389**	4,795
Total utility plant, net	**194,672**	192,896
Other Investments		
Associated companies, at equity	**14,373**	14,545
Other investments	**6,357**	6,120
Total other investments	**20,730**	20,665
Current Assets		
Cash and cash equivalents	**341**	656
Certificate of deposit, pledged as collateral	**15,437**	—
Accounts receivable, customers and others, less allowance for doubtful accounts of $463 and $398	**22,365**	18,503
Accrued utility revenues	**7,093**	6,969
Fuel, materials and supplies, at average cost	**4,056**	3,290
Prepayments	**2,525**	2,197
Income tax receivable	**1,613**	1,241
Other	**222**	382
Total current assets	**53,652**	33,238
Deferred Charges		
Demand side management programs	**6,358**	7,640
Purchased power costs	**11,789**	7,435
Pine Street Barge Canal	**12,370**	8,700
Other	**15,519**	19,521
Total deferred charges	**46,036**	43,296
Non-Utility		
Cash and cash equivalents	**—**	40
Other current assets	**8**	8
Property and equipment	**252**	253
Business segment held for disposal	**—**	9,477
Other assets	**1,258**	1,321
Total non-utility assets	**1,518**	11,099
Total Assets	**$316,608**	$301,194

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • December 31

CAPITALIZATION AND LIABILITIES	2000	1999
	(In thousands)	
Capitalization		
Common Stock Equity		
Common stock, $3.33⅓ par value, authorized 10,000,000 shares (issued 5,582,552 and 5,425,571)	$ 18,608	$ 18,085
Additional paid-in capital	73,321	72,594
Retained earnings	493	10,344
Treasury stock, at cost (15,856 shares)	(378)	(378)
Total common stock equity	92,044	100,645
Redeemable cumulative preferred stock	12,560	12,795
Long-term debt, less current maturities	72,100	81,800
Total capitalization	176,704	195,240
Capital Lease Obligation	6,449	7,038
Current Liabilities		
Current maturities of preferred stock	235	1,640
Current maturities of long-term debt	9,700	6,700
Short-term debt	15,500	7,900
Accounts payable, trade, and accrued liabilities	7,755	6,684
Accounts payable to associated companies	8,510	6,577
Dividends declared	229	285
Customer deposits	696	361
Accrued purchased power option call	8,276	—
Interest accrued	1,150	1,169
Energy East liability	15,419	—
Other	874	8,475
Total current liabilities	68,344	39,791
Deferred Credits		
Accumulated deferred income taxes	25,644	25,201
Unamortized investment tax credits	3,695	3,978
Pine Street Barge Canal site cleanup	11,554	8,815
Other	20,901	21,131
Total deferred credits	61,794	59,125
Commitments and Contingencies	—	—
Non-Utility		
Liabilities of discontinued segment, net	3,317	—
Total non-utility liabilities	3,317	—
Total Capitalization and Liabilities	$316,608	$301,194

The accompanying notes are an integral part of these consolidated financial statements.

A Significant Accounting Policies

1. Organization and Basis of Presentation

Green Mountain Power Corporation (the Company) is an investor-owned electric services company located in Vermont that serves approximately one-quarter of Vermont's population. The most significant portion of the Company's net income is generated from its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 86,000 retail and wholesale customers. At December 31, 2000, the Company's primary subsidiary investment was Mountain Energy Inc., ("MEI"), which had invested in energy generation, energy efficiency and wastewater treatment projects across the United States. In 1999, the Company decided to sell or dispose of the assets of MEI, and report its results as income (loss) from operations of a discontinued segment. MEI changed its name to Northern Water Resources, Inc. ("NWR") in January 2001. In 1998, the Company sold the assets of its wholly owned subsidiary, Green Mountain Propane Gas Company ("GMPG"). The Company's remaining wholly-owned subsidiaries, which are not regulated by the Vermont Public Service Board ("VPSB" or "the Board"), are Green Mountain Resources, Inc. ("GMRI"), which sold its remaining interest in Green Mountain Energy Resources in 1999 and is currently inactive, and GMP Real Estate Corporation. The results of these subsidiaries, excluding MEI, and the Company's unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Statements of Income. Summarized financial information for these subsidiaries is as follows:

	For the years ended December 31,		
	2000	1999	1998
		(In thousands)	
Revenue	$1,034	$1,286	$2,876
Expense	495	184	2,857
Net Income	$ 539	$1,102	$ 19

The Company carries its investments in various associated companies, Vermont Yankee Nuclear Power Corporation ("Vermont Yankee"), Vermont Electric Power Company, Inc. ("VELCO"), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company using the equity method of accounting. The Company's share of the net earnings or losses of these companies is also included in the Other Income section of the Consolidated Statements of Income. See Note B and Note L for additional information.

2. Regulatory Accounting

The Company's utility operations, including accounting records, rates, operations and certain other practices of its electric utility business, are subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC") and the VPSB.

The accompanying consolidated financial statements conform to generally accepted accounting principles applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71 ("SFAS 71"), Accounting for Certain Types of Regulation. Under SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Conditions that could give rise to the discontinuance of SFAS 71 include (1) increasing competition that restricts the Company's ability to establish prices to recover specific costs, and (2) a change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that the Company no longer meets the criteria under SFAS 71, the Company would be required to write off related regulatory assets and liabilities. The Company continues to believe, based on current regulatory circumstances, that the use of regulatory accounting under SFAS 71 remains appropriate and that its regulatory assets are probable of recovery. Regulatory entities that influence the Company include the FERC, the Vermont Department of Public Service ("DPS" or "the Department"), and the VPSB, among other federal, state and local regulatory agencies.

3. Impairment

The Company is required to evaluate long-lived assets, including regulatory assets, for potential impairment. Assets that are no longer probable of recovery through future revenues would be revalued based upon future cash flows. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of December 31, 2000, based upon the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss need be recorded. Competitive influences or regulatory developments may impact this status in the future.

4. Utility Plant

The cost of plant additions includes all construction-related direct labor and materials, as well as indirect construction costs, including the cost of money ("Allowance for Funds Used During Construction" or "AFUDC"). As part of the rate agreement with the DPS, the Company discontinued recording AFUDC on construction work in progress in January 2001. The costs of renewals and improvements of property units are capitalized. The costs of maintenance, repairs and replacements of minor property items are charged to maintenance expense. The costs of units of property removed from service, net of removal costs and salvage, are charged to accumulated depreciation over the estimated service life of the units.

5. Depreciation

The Company provides for depreciation using the straight-line method based on the cost and estimated remaining service life of the depreciable property outstanding at the beginning of the year and adjusted for salvage value and cost of removal of the property.

The annual depreciation provision was approximately 3.5 percent of total depreciable property at the beginning of 2000, and 3.3 percent at the beginning of 1999 and 3.4 percent at the beginning of 1998.

6. Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with maturities less than ninety days.

7. Operating Revenues

Operating revenues consist principally of sales of electric energy. The Company records accrued utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period, in order to match revenues with related costs.

8. Deferred Charges

In a manner consistent with authorized or expected ratemaking treatment, the Company defers and amortizes certain replacement power, maintenance and other costs associated with the Vermont Yankee Nuclear Power Corporation's generation plant. In addition, the Company accrues and amortizes other replacement power expenses to reflect more accurately its cost of service to better match revenues and expenses consistent with regulatory treatment. The Company also defers and amortizes costs associated with its investment in the demand side management program.

Other deferred charges totaled $15.5 million and $19.5 million at December 31, 2000 and 1999 respectively, consisting of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges and various other projects and deferrals.

9. Earnings Per Share

Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. The Company established an incentive stock option plan for all employees during the year ended December 31, 2000, and granted 334,900 options exercisable over vesting schedules of between one and four years. Since the Company experienced a net loss in the year 2000, basic and diluted earnings per share are the same.

10. Major Customers

The Company had one major retail customer, IBM, metered at two locations, that accounted for 11.2 percent, 11.8 percent, and 14.7 percent of total operating revenues, and 16.5 percent, 16.4 percent and 17.1 percent of the Company's retail operating revenues in 2000, 1999 and 1998, respectively. IBM's percent of total revenues in 2000 decreased due to an increase in total operating revenues as a result of sales for resale pursuant to the Morgan Stanley Capital Group, Inc. ("MS") agreement. See Note K for further information regarding the MS agreement.

11. Fair Value of Financial Instruments

The present value of the first mortgage bonds and preferred stock outstanding, if refinanced using prevailing market rates of interest, would decrease from the balances outstanding at December 31, 2000 by approximately 4.6 percent. In the event of such a refinancing, there would be no gain or loss, because under established regulatory precedent, any such difference would be reflected in rates and have no effect upon income.

12. Deferred Credits

At December 31, 2000, the Company had other deferred credits and long-term liabilities of $32.4 million, consisting of reserves for damage claims and environmental liabilities, and accruals for employee benefits compared with a balance of $30.4 million at December 31, 1999.

13. Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect assets and liabilities, the disclosure of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates.

14. Reclassification

Certain items on the prior year's consolidated financial statements have been reclassified to be consistent with the current year presentation.

15. New Accounting Standards

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, amended by Statement No. 137, Accounting for Derivative Instruments and Hedging Activities—Deferral of the Effective Date of FASB Statement No. 133 and Statement 138, Accounting for Certain Derivatives and Certain Hedging Activities (collectively "SFAS 133").

SFAS 133 establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability and measured at their fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 is effective for the Company beginning the first quarter of 2001 and must be applied to derivative instruments and embedded derivatives that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

We have not yet quantified all effects of adopting SFAS 133 on our financial statements. However, a discussion of the Company's material derivative obligations follows and includes estimates of the fair values of each derivative. The Company has sought an accounting order from the VPSB to determine regulatory treatment for recording derivatives at fair market value. We believe it is probable that the VPSB will order that the Company defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133. We expect the VPSB to issue the accounting order prior to reporting our first quarter of 2001 results, and consequently do not anticipate SFAS 133 to cause earnings volatility.

If the VPSB issues such an order, and if a derivative instrument is terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss will be recognized immediately. If such derivative is terminated for other economic reasons, any gain or loss as of the termination date is deferred and recorded when the associated transaction or forecasted transaction affects earnings. For derivatives held to maturity, the income statement impact of derivatives would be recognized in the period that the derivative is sold or matures.

If the VPSB does not issue an order or issues an order that does not require deferral of the earnings impacts resulting from application of SFAS 133, management estimates that adoption would result in earnings/loss recognition equivalent to the fair values of the respective assets/liabilities disclosed below, as adjusted by future changes in estimates.

The Company has a contract with MS used to hedge against increases in fossil fuel prices. MS purchases the majority of Company power supply resources at index (fossil fuel resources) or specified (i.e. contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is a derivative under SFAS 133 and is effective through December 31, 2003.

Management's current estimate of the fair value of the future net benefit (cost) of this arrangement is between $7.2 million and ($14.0) million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments as discussed under Note K. We currently have an arrangement with Hydro-Québec that grants them an option to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2016. Management's current estimate of the fair value of the future net cost (liability) for this arrangement is between $24.5 and $29.5 million.

B Investments in Associated Companies

The Company accounts for investments in the following associated companies by the equity method:

	Percent Ownership at December 31, 2000	Investment in Equity December 31, 2000	1999
		(In thousands)	
VELCO–Common	29.50%	$ 1,916	$ 1,839
–Preferred	30.00%	540	690
Total VELCO		2,456	2,529
Vermont Yankee–Common	17.88%	9,713	9,641
New England Hydro-Transmission–Common	3.18%	827	911
New England Hydro-Transmission Electric–Common	3.18%	1,377	1,464
Total investment in associated companies		$14,373	$14,545

Undistributed earnings in associated companies totaled $908,000 at December 31, 2000.

VELCO

VELCO is a corporation engaged in the transmission of electric power within the State of Vermont. VELCO has entered into transmission agreements with the State of Vermont and other electric utilities, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to the State and others using VELCO's transmission system. The Company's purchases of transmission services from VELCO were $9.7 million, $7.9 million, and $7.1 million for the years 2000, 1999 and 1998, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 30 percent of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis and also is obligated to provide its proportionate share of the equity capital requirements of VELCO through continuing purchases of its common stock, if necessary.

Summarized financial information for VELCO is as follows:

	At and for the years ended December 31, 2000	1999	1998
		(In thousands)	
Company's equity in net income	$ 395	$ 357	$ 338
Total assets	$82,123	$67,294	$67,658
Less:			
Liabilities and long-term debt	73,874	58,731	58,690
Net assets	$ 8,249	$ 8,563	$ 8,968
Company's equity in net assets	$ 2,456	$ 2,529	$ 2,657

Vermont Yankee

The Company is responsible for approximately 17.9 percent of Vermont Yankee's expenses of operations, including costs of equity capital and estimated costs of decommissioning, and is entitled to a similar share of the power output of the nuclear plant, which has a net capacity of 531 megawatts. Vermont Yankee's current estimate of decommissioning costs is approximately $430 million, using the 1993 FERC approved escalation rate of 5.4%, of which $247 million has been funded. At December 31, 2000, the Company's portion of the net unfunded liability was $33 million, which it expects will be recovered through rates over Vermont Yankee's remaining operating life. As a sponsor of Vermont Yankee, the Company also is obligated to provide 20 percent of capital requirements not obtained by outside sources. During 2000, the Company incurred $27.8 million in Vermont Yankee annual capacity charges, which included $2.4 million for interest charges. The Company's share of Vermont Yankee's long-term debt at December 31, 2000 was $17.1 million.

On October 15, 1999, the owners of Vermont Yankee Nuclear Power Corporation accepted a bid from AmerGen Energy Company for the Vermont Yankee generating plant, intending to complete the sale before December 2000. AmerGen and the DPS then negotiated a revised offer in November 2000, which was subsequently dismissed as insufficient by the VPSB in February 2001. Entergy Nuclear Inc. has also made an offer, and two other companies have indicated they would participate in an auction, if held. The plant is likely to be sold at auction, the terms and conditions of which are unknown at this time.

The Price-Anderson Act currently limits public liability from a single incident at a nuclear power plant to $9.5 billion. Any damages beyond $9.5 billion are indemnified under the Price-Anderson Act, but subject to congressional approval. The first $200 million of liability coverage is the maximum provided by private insurance. The Secondary Financial Protection Program is a retrospective insurance plan providing additional coverage up to $9.3 billion per incident by assessing each of the 106 reactor units that are currently subject to the Program in the United States a total of $88.1 million, limited to a maximum assessment of $10 million per incident per nuclear unit in any one year. The maximum assessment is adjusted at least every five years to reflect inflationary changes.

The above insurance covers all workers employed at nuclear facilities for bodily injury claims. Vermont Yankee retains a potential obligation for retrospective adjustments due to past operations of several smaller facilities that did not join the above insurance program. These exposures will cease to exist no later than December 31, 2007. Vermont Yankee's maximum retrospective obligation remains at $3.1 million. Insurance has been purchased from Nuclear Electric Insurance Limited ("NEIL") to cover the costs of property damage, decontamination or premature decommissioning resulting from a nuclear incident. All companies insured with NEIL are subject to retroactive assessments if losses exceed the accumulated funds available. The maximum potential assessment against Vermont Yankee with respect to NEIL losses arising during the current policy year is $8.1 million. Vermont Yankee's liability for the retrospective premium adjustment for any policy year ceases six years after the end of that policy year unless prior demand has been made.

Summarized financial information for Vermont Yankee is as follows:

	At and for the years ended December 31, 2000	1999	1998
		(In thousands)	
Earnings:			
Operating revenues	$178,294	$208,812	$195,249
Net income applicable to common stock	6,583	6,471	7,125
Company's equity in net income	1,177	1,165	1,267
Total assets	$706,984	$685,292	$635,874
Less:			
Liabilities and long-term debt	652,663	631,365	581,231
Net assets	$ 54,321	$ 53,927	$ 54,643
Company's equity in net assets	$ 9,713	$ 9,641	$ 9,759

C Common Stock Equity

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 456,554 shares were reserved and unissued at December 31, 2000. The Company also funds an Employee Savings and Investment Plan ("ESIP"). At December 31, 2000, there were 174,263 shares reserved and unissued under the ESIP.

During 2000, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established an incentive stock option plan. Under this plan, options for up to 500,000 shares may be granted to any employee, officer, consultant, contractor or Director providing services to the Company. Options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date.

As permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), the Company has elected to follow Accounting Principles Board Opinion No. 25 ("APB 25") "Accounting for Stock Issued to Employees", and related interpretations in accounting for its employee stock options. Under APB 25, because the exercise price equals the market price of the underlying stock on the date of grant, no compensation expense is recorded.

Disclosure of proforma information regarding net income and earnings per share is required by SFAS 123. The information presented below has been determined as if the Company accounted for its employee stock options under the fair value method of that statement. The fair values of the options granted in 2000 are $2.03 per share. They were estimated at the grant date using the Black-Scholes option-pricing model with the following weighted average assumptions:

	2000
Risk-free interest rate	6.05%
Expected life in years	7
Expected stock volatility	30.58%
Dividend yield	4.50%

Proforma net earnings loss per share and a summary of options outstanding are as follows:

	2000
Net income (loss) per share	
As reported	($1.25)
Pro-forma	($1.25)
Diluted earnings per share	
As reported	($1.25)
Pro-forma	($1.25)

	Options	Weighted Average Price
Outstanding at 12/31/99	—	$ —
Granted	334,900	7.90
Exercised	—	—
Forfeited	3,400	7.90
Outstanding at 12/31/00	331,500	$7.90

No options granted in 2000 became exercisable in 2000. The proforma amounts may not be representative of future disclosures since the estimated fair value of stock options is amortized to expense over the vesting period and additional options may be granted in future years. For 2000, the number of total shares after giving effect to antidilutive common stock equivalents does not change.

The following summarizes the plan's stock options outstanding:

Plan Year	Weighted Average Exercise Price	Outstanding Shares at 12/31/00	Remaining Contractual Life
2000	$7.90	331,500	9.6 years

During 2000, the Compensation Program for Officers and Certain Key Management personnel, that authorized payment of cash, restricted and unrestricted stock grants based on corporate performance was replaced with the incentive stock option plan discussed above. Approximately 2000 restricted shares, issued during 1996 and 1997, remained unvested under this program.

Changes in common stock equity for the years ended December 31, 1998, 1999 and 2000 are as follows:

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Stock Equity
				(Dollars in thousands)			
BALANCE, December 31, 1997	**5,195,432**	**$17,318**	**$70,720**	**$26,717**	**15,856**	**($378)**	**$114,377**
Common Stock Issuance:							
DRIP	88,004	293	928				1,221
ESIP	36,391	121	427				548
Compensation Program:							
Restricted Shares	(6,531)	(21)	(161)				(182)
Net Loss				(2,877)			(2,877)
Cash Dividends on Capital Stock:							
Common Stock				(5,036)			(5,036)
Preferred Stock—$4.75 per share				(12)			(12)
—$7.00 per share				(32)			(32)
—$9.375 per share				(72)			(72)
—$8.625 per share				(302)			(302)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 1998	**5,313,296**	**17,711**	**71,914**	**17,508**	**15,856**	**(378)**	**106,755**
Common Stock Issuance:							
DRIP	67,525	225	418				643
ESIP	48,277	161	345				506
Compensation Program:							
Restricted Shares	(3,527)	(12)	(83)				(95)
Net Loss				(3,063)			(3,063)
Cash Dividends on Capital Stock:							
Common Stock				(2,946)			(2,946)
Preferred Stock—$4.75 per share				(10)			(10)
—$7.00 per share				(29)			(29)
—$9.375 per share				(57)			(57)
—$8.625 per share				(181)			(181)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 1999	**5,425,571**	**18,085**	**72,594**	**10,344**	**15,856**	**(378)**	**100,645**
Common Stock Issuance:							
DRIP	73,859	246	363				609
ESIP	83,931	280	401				681
Compensation Program:							
Restricted Shares	(809)	(3)	(37)				(40)
Net Loss				(5,840)			(5,840)
Cash Dividends on Capital Stock:							
Common Stock				(2,997)			(2,967)
Preferred Stock—$4.75 per share				(8)			(8)
—$7.00 per share				(26)			(26)
—$9.375 per share				(42)			(42)
—$8.625 per share				(60)			(60)
—$7.32 per share				(878)			(878)
BALANCE, December 31, 2000	**5,582,552**	**$18,608**	**$73,321**	**$ 493**	**15,856**	**($378)**	**$ 92,044**

Dividend Restrictions

Certain restrictions on the payment of cash dividends on common stock are contained in the Company's indentures relating to long-term debt and in the Restated Articles of Association. Under the most restrictive of such provisions, approximately $0.5 million of retained earnings were free of restrictions at December 31, 2000.

The properties of the Company include several hydroelectric projects licensed under the Federal Power Act, with license expiration dates ranging from 2001 to 2025. At December 31, 2000, $161,000 of retained deficit had been appropriated as excess earnings on hydroelectric projects as required by Section 10(d) of the Federal Power Act.

D Preferred Stock

The holders of the preferred stock are entitled to specific voting rights with respect to certain types of corporate actions. They are also entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors in the event of preferred stock dividend arrearages equivalent to or exceeding four quarterly dividends. Similarly, the holders of the preferred stock are entitled to elect two directors in the event of default in any purchase or sinking fund requirements provided for any class of preferred stock.

Certain classes of preferred stock are subject to annual purchase or sinking fund requirements. The sinking fund requirements are mandatory. The purchase fund requirements are mandatory, but holders may elect not to accept the purchase offer. The redemption or purchase price to satisfy these requirements may not exceed $100 per share plus accrued dividends. All shares redeemed or purchased in connection with these requirements must be canceled and may not be reissued. The annual purchase and sinking fund requirements for the year 2001 for certain classes of preferred stock are as follows:

	Purchase and Sinking Fund Due Dates	Shares to Retire
Class:		
4.750%, Class B	December 1	300
7.000%, Class C	December 1	450
9.375%, Class D, Series 1	December 1	1,600

Under the Restated Articles of Association relating to Redeemable Cumulative Preferred Stock, the annual aggregate amount of purchase and sinking fund requirements for the next five years are $235,000 each for 2001 and 2002, $75,000 each for 2003 and 2004, $70,000 for 2005 and $105,000 thereafter.

Certain classes of preferred stock are redeemable at the option of the Company or, in the case of voluntary liquidation, at various prices on various dates. The prices include the par value of the issue plus any accrued dividends and a redemption premium. The redemption premium for Class B, C and D, Series 1, is $1.00 per share.

E Long-Term Debt

Substantially all of the property and franchises of the Company are subject to the lien of the indenture under which first mortgage bonds have been issued. The weighted average rate on long term borrowings outstanding was 7.6 percent and 7.5 percent at December 31, 2000 and 1999, respectively. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) and long-term debt maturities for the next five years are:

	Sinking Funds	Maturities	Total
		(In thousands)	
2001	$1,700	$8,000	$9,700
2002	1,700	8,000	9,700
2003	1,700	8,000	9,700
2004	1,700	—	1,700
2005	1,700	—	1,700

F Short-Term Debt

The Company has a revolving credit agreement with Fleet Financial Services and Citizens Bank of Massachusetts (the "Fleet agreement") in the amount of $15.0 million, with borrowings outstanding of $500,000 and $7.9 million at December 31, 2000 and 1999, respectively. The 364-day agreement expires June 2001. The weighted average interest rate on short-term borrowings outstanding at December 31, 2000 and December 31, 1999 was 9.5 percent and 9.0 percent, respectively. There was no non-utility short-term debt outstanding at December 31, 2000.

The Fleet agreement requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change". Similarly, as a condition to further borrowings, the Company must certify that no event has occurred or failed to occur that has had or would reasonably be expected to have a materially adverse effect on the Company since the date of the last borrowing under this agreement. The Fleet agreement allows the Company to continue to borrow until such time that:

- a "material adverse effect" has occurred; or
- the Company no longer complies with all other provisions of the agreement, in which case further borrowing will not be permitted; or
- there has been a "material adverse change", in which case the banks may declare the Company in default.

Terms also call in part for a second priority mortgage lien and security interest in the collateral pledged under the first mortgage bond indenture.

On September 20, 2000, we established a $15.0 million revolving credit agreement ("KeyBank agreement") with KeyBank National Association ("KeyBank"). The KeyBank agreement is for a period of 364 days and will expire on September 19, 2001. Pursuant to a one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE upon request after September 2001. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of indebtedness issued under the Keybank agreement. At December 31, 2000, there was $15.0 million outstanding on the KeyBank Agreement.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2001. The VPSB Order of January 23, 2001, (the "Settlement Order"), will likely permit restoration of the Company's investment grade debt ratings, allowing arrangement of such financing as the Company needs during 2001.

G Income Taxes

Utility

The Company accounts for income taxes using the liability method. This method accounts for deferred income taxes by applying statutory rates to the differences between the book and tax bases of assets and liabilities.

The regulatory tax assets and liabilities represent taxes that will be collected from or returned to customers through rates in future periods. As of December 31, 2000 and 1999, the net regulatory assets were $1,908,000 and $1,805,000, respectively, and included in other deferred charges on the Company's consolidated balance sheets.

The temporary differences which gave rise to the net deferred tax liability at December 31, 2000 and December 31, 1999, were as follows:

	At December 31, 2000	1999
	(In thousands)	
Deferred Tax Assets		
Contributions in aid of construction	$10,018	$ 9,056
Deferred compensation and postretirement benefits	4,122	3,372
Self-insurance and other reserves	—	3,664
Other	1,958	1,183
	16,098	17,275
Deferred Tax Liabilities		
Property-related	38,648	37,946
Demand side management	1,810	2,328
Deferred purchased power costs	84	2,202
Pine Street reserve	571	25
Other	629	—
	41,742	42,476
Net accumulated deferred income tax liability	$25,644	$25,201

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the income statement for the period:

	Years ended December 31, 2000	1999	1998
	(In thousands)		
Net change in deferred income tax liability	$443	$1,812	($112)
Change in income tax related regulatory assets and liabilities	184	176	510
Changes in alternative minimum tax credit	—	—	(70)
Deferred income tax expense (benefit)	$627	$1,988	$ 328

The components of the provision for income taxes are as follows:

	Years ended December 31, 2000	1999	1998
	(In thousands)		
Current federal income taxes	($ 786)	($ 339)	($1,047)
Current state income taxes	(249)	(125)	(366)
Total current income taxes	(1,035)	(464)	(1,413)
Deferred federal income taxes	461	1,479	219
Deferred state income taxes	166	509	109
Total deferred income taxes	627	1,988	328
Investment tax credits—net	(283)	(282)	(282)
Income tax provision (benefit)	($ 691)	$ 1,242	($1,367)

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	Years ended December 31, 2000	1999	1998
	(In thousands)		
Income (loss) before income taxes and preferred dividends	($6,531)	($1,821)	($4,244)
Federal statutory rate	34.0%	34.0%	34.0%
Computed "expected" federal income taxes	(2,221)	(619)	(1,443)
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation	83	92	153
Dividends received and paid credit	(435)	(485)	(480)
AFUDC–equity funds	(33)	(5)	(36)
Amortization of ITC	(282)	(282)	(282)
State tax (benefit)	(83)	383	(256)
Excess deferred taxes	(60)	(60)	(60)
Taxes attributable to subsidiaries	2,213	2,271	845
Other	127	(53)	192
Total federal and state income tax (benefit)	($ 691)	$ 1,242	($1,367)
Effective combined federal and state income tax rate	10.6%	(68.2)%	32.2%

Non-Utility

The Company's non-utility subsidiaries, excluding MEI, had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2000, attributable to depreciation timing differences.

The components of the provision for the income tax expense (benefit) for the non-utility operations are:

	Years ended December 31, 2000	1999	1998
	(In thousands)		
State income taxes	$ 7	$ 99	($281)
Federal income taxes	21	310	(202)
Income tax expense (benefit)	$28	$409	($483)

The effective combined federal and state income tax rates for the continuing non-utility operations were 34.0 percent, 34.0 percent, and 32.6 percent, for the years ended December 31, 2000, 1999 and 1998, respectively. See Note L for income tax information on the discontinued operations of MEI.

H Pension and Retirement Plans

The Company has a defined benefit pension plan covering substantially all of its employees. The retirement benefits are based on the employees' level of compensation and length of service. The Company's policy is to fund all accrued pension costs. The Company records annual expense and accounts for its pension plan in accordance with Statement of Financial Accounting Standards Number 87, Employers' Accounting for Pensions. The Company provides certain health care benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach normal retirement age while working for the Company. The Company accrues the cost of these benefits during the service life of covered employees. The pension plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities.

Accrued postretirement health care expenses are recovered in rates to the extent those expenses are funded. In order to maximize the tax-deductible contributions that are allowed under IRS regulations, the Company amended its pension plan to establish a 401-h sub-account and separate VEBA trusts for its union and non-union employees. The VEBA plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities. The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans as of December 31, 2000 and 1999:

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end	$ 22,444	$ 30,860	$11,955	$12,552
Service cost	655	620	216	240
Interest cost	1,658	1,780	1,049	855
Special termination benefit	—	5,385	—	1,446
Change in actuarial assumptions	—	—	2,328	(1,372)
Settlements	—	(9,527)	—	—
Actuarial (gain) loss	513	(2,080)	73	(70)
Benefits paid	(1,938)	(4,312)	(674)	(864)
Curtailment	—	(282)	—	(832)
Projected benefit obligation as of year end	$ 23,332	$ 22,444	$14,947	$11,955
Change in plan assets:				
Fair value of plan assets as of prior year end	$ 31,477	$ 38,030	$11,062	$ 9,735
Contribution	—	—	—	—
Actual return on plan assets	(1,779)	7,286	(118)	1,327
Benefits paid	(1,938)	(13,839)	—	—
Fair value of plan assets as of year end	$ 27,760	$ 31,477	$10,944	$11,062
Funded status as of year end	$ 4,428	$ 9,032	($4,003)	($ 893)
Unrecognized transition obligation (asset)	(406)	(571)	3,936	4,264
Unrecognized prior service cost	766	887	(577)	(635)
Unrecognized net actuarial gain	(6,848)	(12,193)	(130)	(3,589)
Accrued benefits at year end	($ 2,060)	($ 2,845)	($ 774)	($ 853)

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2000, 1999, and 1998 were $346,000, $556,000, and $397,000, respectively, under this plan. This plan is funded in part through insurance contracts.

Net periodic pension expense and other postretirement benefit costs include the following components:

	For the years ended December 31,					
	Pension Benefits			Other Postretirement Benefits		
	2000	1999	1998	2000	1999	1998
	(In thousands)					
Service cost	$ 655	$ 620	$ 787	$ 216	$ 240	$ 282
Interest cost	1,658	1,780	2,043	1,049	855	799
Expected return on plan assets	(2,580)	(2,721)	(3,081)	(940)	(834)	(671)
Amortization of transition asset	(164)	(196)	(228)	—	—	—
Amortization of net gain from earlier periods	—	—	—	—	—	—
Amortization of prior service cost	121	128	134	(58)	(60)	(61)
Amortization of the transition obligation	—	—	—	328	340	351
Recognized net actuarial gain	(474)	(196)	(195)	—	(19)	—
Special termination benefit	—	3,122	2,026	—	888	27
Regulatory deferral	—	(3,122)	(2,026)	—	(888)	(27)
Net periodic benefit cost	($ 784)	($ 585)	($ 540)	$ 595	$ 522	$ 700

Assumptions used to determine postretirement benefit costs and the related benefit obligation were:

	For the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
Weighted average assumptions as of year end:				
Discount rate	7.50%	6.75%	7.50%	7.50%
Expected return on plan assets	9.00%	9.00%	8.50%	8.50%
Rate of compensation increase	4.50%	4.00%	—	—
Medical inflation	—	—	6.00%	5.30%

For measurement purposes, a 6 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2000 and later years. The health care cost trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed health care cost trend rate by one percentage point for all future years would increase the accumulated postretirement benefit obligation as of December 31, 2000 by $1.9 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2000 by $200,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2000 by $1.5 million, and the total of the service and interest cost components of net periodic postretirement cost for 2000 by $157,000.

In 1999, the Company deferred special termination pension benefit costs of $3,122,000 due to an early retirement program and other employee separation activities. Curtailment and settlement gains of $2.3 million are included in the special termination pension benefit cost. The special termination benefit recorded in 1998 resulted from the early retirement option offered to employees in 1998. Also in 1999, the Company deferred special termination postretirement benefit costs of $888,000 due to an early retirement program. Management believes that the amounts deferred are probable of recovery.

I Commitments and Contingencies

1. Industry Restructuring

The electric utility business is being subjected to rapidly increasing competitive pressures stemming from a combination of trends. Certain states, including all the New England states except Vermont, have enacted legislation to allow retail customers to choose their electric suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Recent power supply management difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards de-regulation in Vermont. There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered.

2. Environmental Matters

The electric industry typically uses or generates a range of potentially hazardous products in its operations. The Company must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with those requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site. The Company maintains an environmental compliance and monitoring program that includes employee training, regular inspection of Company facilities, research and development projects, waste handling and spill prevention procedures and other activities.

Pine Street Barge Canal Site

The Federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), commonly known as the "Superfund" law, generally imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. The Company has been notified by the Environmental Protection Agency ("EPA") that it is one of several potentially responsible parties ("PRPs") for cleanup of the Pine Street Barge Canal site in Burlington, Vermont, where coal tar and other industrial materials were deposited.

In September 1999, we negotiated a final settlement with the United States, the State of Vermont, and other parties over terms of a Consent Decree that covers claims addressed in the earlier negotiations and implementation of the selected remedy. In November 1999, the Consent Decree was filed in the federal district court. The Consent Decree addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site.

As of December 31, 2000, the Company's total expenditures related to the Pine Street Barge Canal site since 1982 were approximately $23.5 million. This includes those amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently awaiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier, and more costly, proposals for the site, as well as litigation and related costs necessary to obtain settlements with insurers and other PRP's to provide amounts required to fund the clean up (remediation costs) and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to the EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million over the next 33 years. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset and we believe that it is probable that we will receive future revenues to recover these costs. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street Barge Canal site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers". The VPSB Order released January 23, 2001 regarding the Company's 1998 retail rate request, did not change the status of Pine Street cost recovery.

Clean Air Act

The Company purchases most of its power supply from other utilities and does not anticipate that it will incur any material direct costs as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act.

3. Operating Leases

The Company terminated an operating lease for its corporate headquarters building and two of its service center buildings in the first quarter of 1999. During 1998, the Company recorded a loss of approximately $1.9 million before applicable income taxes to reflect the probable loss resulting from this transaction. The Company sold its corporate headquarters building in 1999, but retained ownership of the two service centers.

4. Jointly-Owned Facilities

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2000, as follows:

	Ownership Interest	Share of Capacity	Utility Plant	Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$10,299	$4,118
McNeil	11.0	5.9	8,866	4,484
Stony Brook (No. 1)	8.8	31.0	10,339	7,636
Wyman (No. 4)	1.1	6.8	1,980	1,192
Metallic Neutral Return	59.4	—	1,563	619

Metallic Neutral Return is a neutral conductor for NEPOOL/Hydro-Québec Interconnection.

The Company's share of expenses for these facilities is reflected in the Consolidated Statements of Income. Each participant in these facilities must provide its own financing.

5. Rate Matters

Retail Rate Cases

On March 2, 1998, the VPSB released its Order dated February 27, 1998 in the then pending rate case. The VPSB authorized us to increase our rates by 3.61 percent, which gave us increased annual revenues of $5.6 million. The VPSB Order denied us the right to charge customers $5.48 million of the annual costs for power purchased under our contract with Hydro-Québec. The VPSB denied recovery of these costs for the following reasons:

- the VPSB claimed that we had acted imprudently by committing to the power contract with Hydro-Québec in August 1991 (the imprudence disallowance); and
- to the extent that the costs of power to be purchased from Hydro-Québec were then higher than current estimates of market prices for power during the contract term, after accounting for the imprudence disallowance, the contract power was not "used and useful". On May 8, 1998, we filed a request with the VPSB to increase our retail rates by 12.93 percent due to higher power costs, the cost of the January 1998 ice storm, and investments in new plant and equipment.

On November 18, 1998, by Memorandum of Understanding (MOU), the Company, the Department and IBM agreed to stay rate proceedings in the 1998 rate case until or after September 1, 1999, or such earlier date as the parties may later agree to or the VPSB may order. The agreement to suspend our 1998 rate case delayed the date of a final decision on the 1998 rate case to December 15, 1999, and we recognized an additional loss of $5.25 million in the last quarter of 1998 representing the effect of the continued disallowance of Hydro-Québec costs through December 15, 1999. The MOU provided for a 5.5% temporary retail rate increase, to produce $8.9 million in annualized additional revenue, effective with service rendered December 15, 1998. An additional surcharge was permitted, without further VPSB order, in order to produce additional revenues necessary to provide the Company with the capacity to finance 1999 Pine Street Barge Canal site expenditures. The MOU was approved by the VPSB on December 11, 1998. The MOU did not provide for any specific disallowance of power costs under our purchase power contract with Hydro-Québec. Issues respecting recovery of such power costs were preserved for future proceedings.

The stay and suspension of this pending rate case and the temporary rate levels agreed to in the MOU were designed to allow us to continue to provide adequate and efficient service to our customers while we sought mitigation of power supply costs.

On September 7 and December 17, 1999, the VPSB issued Orders approving two amendments to the MOU that the Company had entered into with the Department and IBM. The two amendments continued the stay of proceedings until September 1, 2000, with a final decision expected by December 31, 2000. The amendments maintained the other features of the original MOU, and the second amendment provided for a temporary rate increase of 3 percent, in addition to the prior temporary rate level, to become effective as of January 1, 2000.

The Company reached a final settlement agreement with the VDPS in the pending rate case during November 2000. The final settlement agreement contains the following provisions:

- A rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases become permanent;
- Rates are set at levels that recover the Company's Hydro-Québec contract costs, effectively ending the regulatory disallowances experienced by the Company over the past three years;
- The Company agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
- The Company agrees to write off approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
- Seasonal rates will be eliminated in April, 2001, which is expected to generate approximately $6 million in cash flow that can be utilized to offset increased costs during 2001, 2002 and 2003; and
- The Company agrees to consult extensively with the DPS regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions. The Settlement Order requires the Company and customers to share equally any premium above book value realized by the Company, subject to an $8.0 million limit, in any future merger, acquisition or asset sale. The second condition restricts Company investments in non-utility operations.

6. Transmission

A FERC ruling in December 2000 required ISO New England to revise its installed capability ("ICAP") deficiency charge of $0.17 per kw month to $8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, the FERC suspended its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for rehearing, which, if successful, would then require extensive refunds and surcharges." On March 6, 2001, FERC issued an Order on Rehearing in which it partly reversed itself on the ICAP charge. Although the Commission first concluded that a $8.75 charge is reasonable and that the charge would remain in place until the ISO supports an acceptable superceding proposal, the Commission then concluded that reinstating the $8.75 would have a large cost impact. As a result, the $0.17 per kw month charge was reinstated from August 1, 2000 until April 1, 2001. The Commission allowed the $8.75 charge to become effective on April 1, 2001 until the effective date of any superceding charge the Commission might accept. As a result, the Company should have no exposure to paying the difference in the two charges for the period from August 1, 2000 until April 1, 2001.

7. Deferred Charges Not Included in Rate Base

The Company has incurred and deferred approximately $3.0 million in costs for tree trimming, storm damage and federal regulatory commission work of which $2.8 million will be amortized over five years ending in December 2005. Currently, the Company amortizes such costs based on historical averages and does not receive a return on amounts deferred. Management expects to seek and receive ratemaking treatment for these costs in future filings.

The Settlement Order directed the Company to write-off deferred charges applicable to the state regulatory commission of $3.2 million as part of the rate case agreement with the DPS. The charge is included in other operating expense for the year ended December 31, 2000. The Order requires the remaining balance and future expenditures of deferred regulatory commission charges be amortized over seven years.

8. Other Legal Matters

The Company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material effect on the financial position or the results of operations of the Company.

J Obligations Under Transmission Interconnection Support Agreement

Agreements executed in 1985 among the Company, VELCO and other NEPOOL members and Hydro-Québec provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of Hydro-Québec. Phase II expands the Phase I facilities from 690 megawatts to 2,000 megawatts and provides for transmission of Hydro-Québec power from the Phase I terminal in northern New Hampshire to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 3.2 percent of the Phase II power-supply benefits. Total construction costs for Phase II were approximately $487 million. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under thirty-year agreements. These support agreements meet the capital lease accounting requirements under SFAS 13. At December 31, 2000, the present value of the Company's obligation is approximately $6.4 million.

Projected future minimum payments under the Phase II support agreements are as follows:

	Year ending December 31, (In thousands)
2001	$ 430
2002	430
2003	430
2004	430
2005	430
Total for 2006–2020	4,299
Total	$6,449

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities.

K Long-Term Power Purchases

1. Unit Purchases

Under long-term contracts with various electric utilities in the region, the Company is purchasing certain percentages of the electrical output of production plants constructed and financed by those utilities. Such contracts obligate the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements whether or not the production plants are operating. The cost of power obtained under such long-term contracts, including payments required when a production plant is not operating, is reflected as "Power Supply Expenses" in the accompanying Consolidated Statements of Income.

Information (including estimates for the Company's portion of certain minimum costs and ascribed long-term debt) with regard to significant purchased power contracts of this type in effect during 2000 follows:

	Stony Brook	Vermont Yankee
	(Dollars in thousands)	
Plant capacity	352.0 MW	531.0 MW
Company's share of output	4.40%	17.90%
Contract period	(1)	(2)
Company's annual share of:		
Interest	$ 189	$ 2397
Other debt service	347	—
Other capacity	497	25,401
Total annual capacity	$1,033	$27,798
Company's share of long-term debt	$3,194	$17,181

(1) Life of plant estimated to be 1981–2006.
(2) License for plant operations expires in 2012.

2. Hydro-Québec System Power Purchase and Sale Commitments

Under various contracts, the details of which are described in the table below, the Company purchases capacity and associated energy produced by the Hydro-Québec system. Such contracts obligate the Company to pay certain fixed capacity costs whether or not energy purchases above a minimum level set forth in the contracts are made. Such minimum energy purchases must be made whether or not other, less expensive energy sources might be available. These contracts are intended to complement the other components in the Company's power supply to achieve the most economic power-supply mix reasonably available.

The Company's current purchases pursuant to the contract with Hydro-Québec entered into December 4, 1987 (the 1987 Contract) are as follows: (1) Schedule B—68 megawatts of firm capacity and associated energy to be delivered at the Highgate interconnection for twenty years beginning in September 1995; and (2) Schedule C3—46 megawatts of firm capacity and associated energy to be delivered at interconnections to be determined at any time for 20 years, which began in November 1995.

During 1994, the Company negotiated an arrangement with Hydro-Québec that reduces the cost impacts associated with the purchase of Schedules B and C3 under the 1987 Contract, over the November 1995 through October 1999 period (the July 1994 Agreement). Under the July 1994 Agreement, the Company, in essence, will take delivery of the amounts of energy as specified in the 1987 Contract, but the associated fixed costs will be significantly reduced from those specified in the 1987 Contract.

As part of the July 1994 Agreement, we were obligated to purchase $4.0 million (in 1994 dollars) worth of research and development work from Hydro-Québec over a period ending October 1999 (which has since been extended), and made an additional $6.5 million (plus accrued interest) payment to Hydro-Québec in 1995. Hydro-Québec retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2000 to 2015 period, if documented drought conditions exist in Québec. The period for completing the research and development purchase was subsequently extended to March 2001.

During the first year of the July 1994 Agreement (the period from November 1995 through October 1996), the average cost per kilowatt-hour of Schedules B and C3 combined was cut from 6.4 to 4.2 cents per kilowatt-hour, a 34 percent (or $16 million) cost reduction. Over the period from November 1996 through December 2000 and accounting for the payments to Hydro-Québec, the combined unit costs will be lowered from 6.5 to 5.9 cents per kilowatt-hour, reducing unit costs by 10 percent and saving $20.7 million in nominal terms.

All of the Company's contracts with Hydro-Québec call for the delivery of system power and are not related to any particular facilities in the Hydro-Québec system. Consequently, there are no identifiable debt-service charges associated with any particular Hydro-Québec facility that can be distinguished from the overall charges paid under the contracts.

A summary of the Hydro-Québec contracts, including the July 1994 Agreement, but excluding the January and November 1996 arrangements (described below) including historic and projected charges for the years indicated, follows:

	The 1987 Contract	
	Schedule B	Schedule C3
	(Dollars in thousands except per KWH)	
Capacity Acquired	68 MW	47 MW
Contract Period	1995–2015	1995–2015
Minimum Energy Purchase (annual load factor)	75%	75%
Annual Energy Charge 2000	$10,471	$7,105
Estimated 2001–2015	$13,506*	$9,320*
Annual Capacity Charge 2000	$16,850	$11,727
Estimated 2001–2015	$16,686*	$11,523*
Average Cost per KWH 2000	6.8¢	6.9¢
Estimated 2001–2015	7.0¢**	7.0¢**

*Estimated average.
**Estimated average in nominal dollars levelized over the period indicated.
Includes amortization of payments to Hydro-Québec for the July 1994 Agreement.

Under a 1996 arrangement ("9601"), the Company is required to shift up to 40 megawatts of its Schedule C3 to an alternate transmission path and use the associated portion of the NEPOOL/Hydro-Québec interconnection facilities to purchase power for the period from September 1996 through June 2001 at prices that vary based upon conditions in effect when the purchases were made. The 1996 arrangement also provides for minimum payments by the Company to Hydro-Québec for the periods in which power is not purchased under the arrangement. The 9601 arrangement allows Hydro-Québec to curtail energy deliveries should it need to use certain resources to supplement available supply. During the last three months of 2000, Hydro-Québec did curtail energy deliveries. Although the level of benefits to the Company will depend on various factors, the Company estimates that the 1996 arrangement will provide a benefit of approximately $3.0 million on a net present value basis.

Under a separate agreement executed on December 5, 1997 ("9701"), Hydro-Québec provided a payment of $8.0 million to the Company in 1997. In return for this payment, the Company provided Hydro-Québec an ongoing option for the purchase of power. Commencing April 1, 1998, and effective through October 2015, Hydro-Québec can exercise an option to purchase up to 52,500 MWh ("option A") on an annual basis, at energy prices established in accordance with the 1987 Contract. The cumulative amount of energy purchased under this agreement shall not exceed 950,000 MWh. Hydro-Québec's option to curtail energy deliveries pursuant to the July 1994 Agreement may be exercised in addition to these purchase options.

Over the same period, Hydro-Québec can exercise an option on an annual basis to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Hydro-Québec can purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2000, Hydro-Québec had purchased or called to purchase 349,000 MWh under option B, including calls for January and February of 2001.

In 2000, Hydro-Québec called for deliveries to third parties at a net cost to the Company of approximately $14.0 million (including the cost of the January and February 2001 calls and related financial positions), which was due to higher energy replacement costs. Approximately $6.6 million of 9701 costs are recovered currently in rates on an annual basis. The VPSB, in the Settlement Order said, "The record does not demonstrate that any other New England utility foresaw the extent and degree of volatility that has developed in the New England wholesale power markets. Absent that volatility, the 9701 Agreement would not have had adverse effects." In conjunction with the Settlement Order, Hydro-Québec committed to the DPS that it would not call any energy under option B of the 9701 arrangement during 2002. In 1999, Hydro-Québec called for deliveries to third parties at a net cost to the Company of approximately $6.3 million. The Company's estimate of the fair value of the future net cost for this arrangement, which is dependent upon the timing of any exercise of options and the market price for replacement power, is between $24.5 and $29.5 million. Future estimates could change by a material amount.

In 1999, the Company and the other Vermont Joint Owners (VJO) of the Hydro-Québec contract initiated an arbitration against Hydro-Québec, pursuant to the 1987 contract terms, to determine whether the suspension of deliveries of power to Vermont during and after the January 1998 ice storm evidenced a default by Hydro-Québec under the terms of the contract. Hydro-Québec maintains that the "force majeure" (superior or irreversible force) provision in the contract applies, which could excuse its non-delivery of power under these circumstances. Arbitration of the dispute may lead to remedies having a material impact on our contractual obligation, including the possibility that the contract be declared terminated or void. If arbitration results in a cash payment, it will first be applied to a regulatory asset of $4.7 million for arbitration litigation costs. If the contract is declared terminated or void, the Company would have to replace a substantial amount of its power needs at terms which could materially exceed the 1987 Contract price for 2001. The Company believes that it could contract replacement power at costs substantially below the long term costs of the 1987 Contract. The Settlement Order provides that the Company will not earn a return on these litigation costs, unless the case results in lower power supply costs for ratepayers. A decision is expected in this arbitration in April 2001.

3. Morgan Stanley Agreement

On February 11, 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. (MS). In January 2001, the MS arrangement was modified and extended to December 31, 2003. The arrangement provides us a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, the Company will sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to the Company, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. The Company remains responsible for resource performance and availability. MS provides no coverage against major unscheduled outages.

L Discontinued Operations

The Company has decided to sell or otherwise dispose of the operations and assets of MEI, which owns and invests in energy generation, energy efficiency, and wastewater treatment projects. MEI has been reported as a separate segment in 1998 and prior years, and appeared as a separate "Equity investment in energy related business" caption in the nonutility section of the consolidated balance sheet. Results of operations were previously included in the section Other Income in the consolidating statements of income. In 1999 and 2000, assets and liabilities are presented net in the nonutility section as "Business segment held for disposal", or "Liability of discontinued segment". The provisions for loss from discontinued operations reflect management's current estimate. Risk factors associated with the discontinuation of MEI operations include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment have commenced or threatened litigation. The ultimate loss remains subject to the disposition of remaining assets and liabilities, and could exceed the amounts recorded. The following illustrates the results and financial statement impact of MEI during and at the periods shown:

	2000	1999	1998
	(In thousands except per share)		
Revenues	$ 1,546	$ 2,296	$ 2,092
Net income (loss) operations	—	(603)	(2,086)
Provisions for loss on disposal and future operating losses	(6,549)	(6,676)	—
Net income (loss)	($6,549)	($7,279)	($2,086)
Net income (loss) per share	($1.19)	($1.36)	($0.40)

Income taxes for MEI for the years ended December 31, 2000, 1999 and 1998 are summarized as:

	Years ended December 31, 2000	1999	1998
		(In thousands)	
State income taxes	($1,064)	($ 281)	($ 222)
Federal income taxes	(3,349)	(1,371)	(1,130)
Investment tax credits	—	—	(111)
Income tax expense (benefit)	($4,413)	($1,652)	($1,463)

M Quarterly Financial Information (Unaudited)

The following quarterly financial information, in the opinion of management, includes all adjustments necessary to a fair statement of results of operations for such periods. Variations between quarters reflect the seasonal nature of the Company's business and the timing of rate changes.

	2000 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$67,712	$61,927	$78,143	$69,544	$277,326
Operating income (loss)	4,613	(2,997)	3,271	373	5,260
Net income (loss) from continuing operations	$ 3,449	($4,375)	$ 1,961	($1,340)	($ 305)
Net loss from discontinued operations	—	(1,530)	—	(5,019)	(6,549)
Net income (loss) applicable to common stock	$ 3,449	($5,905)	$ 1,961	($6,359)	($ 6,854)
Earnings (loss) per average share from:					
Continuing operations	$ 0.63	($ 0.80)	$ 0.36	($ 0.25)	($ 0.06)
Discontinued operations	—	(0.28)	—	(0.91)	(1.19)
Basic and diluted	$ 0.63	($ 1.08)	$ 0.36	($ 1.16)	($ 1.25)
Weighted average common shares outstanding	5,437	5,472	5,505	5,551	5,491

	1999 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$59,018	$59,535	$68,478	$64,017	$251,048
Operating income	3,906	977	1,412	1,651	7,946
Net income (loss) from continuing operations	$ 3,170	($ 412)	($ 115)	$ 418	$ 3,061
Net loss from discontinued operations	(522)	(81)	(4,592)	(2,084)	(7,279)
Net income (loss) applicable to common stock	$ 2,648	($ 493)	($4,707)	($1,666)	($ 4,218)
Earnings (loss) per average share from:					
Continuing operations	$ 0.60	($ 0.08)	($ 0.02)	$ 0.07	$ 0.57
Discontinued operations	(0.10)	(0.02)	(0.85)	(0.39)	(1.36)
Basic and diluted	$ 0.50	($ 0.10)	($ 0.88)	($ 0.31)	($ 0.79)
Weighted average common shares outstanding	5,318	5,344	5,374	5,291	5,361

	1998 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$46,932	$43,733	$47,984	$45,655	$184,304
Operating income	316	2,811	3,147	(802)	5,472
Net income (loss) from continuing operations	($2,648)	$ 1,286	$ 1,811	($2,536)	($ 2,087)
Net loss from discontinue operations	(757)	(355)	(178)	(796)	(2,086)
Net income (loss) applicable to common stock	($3,405)	$ 931	$ 1,633	($3,332)	($ 4,173)
Earnings (loss) per average share from:					
Continuing operations	($ 0.51)	$ 0.25	$ 0.34	($ 0.48)	($ 0.40)
Discontinued operations	(0.15)	(0.06)	(0.03)	(0.16)	(0.40)
Basic and diluted	($ 0.66)	$ 0.18	$ 0.31	($ 0.63)	($ 0.80)
Weighted average common shares outstanding	5,196	5,222	5,261	5,291	5,243

Report of Independent Public Accountants

**To the Board of Directors of
Green Mountain Power Corporation:**

We have audited the accompanying consolidated balance sheets and consolidated capitalization data of Green Mountain Power Corporation (a Vermont corporation) and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and its subsidiaries as of December 31, 2000 and 1999, and the consolidated results of its operations and 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.

Arthur Andersen LLP

Boston, Massachusetts
February 2, 2001

Consolidated Statements of Income

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

In thousands, except per share amounts	2000	1999	1998
Operating Revenues			
Residential	**$ 69,832**	$ 67,061	$ 61,697
Lease	**—**	—	—
Total residential and lease	**69,832**	67,061	61,697
Commercial and industrial–small	**70,382**	68,004	61,816
Commercial and industrial–large	**45,729**	43,518	40,201
Sales for resale	**88,333**	68,305	16,529
Other	**3,050**	4,160	4,061
Total operating revenues	**277,326**	251,048	184,304
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**34,813**	34,987	32,910
Company-owned generation	**9,756**	5,582	6,412
Purchases from others	**168,947**	142,699	81,706
Other operating	**17,644**	17,582	21,291
Transmission	**12,258**	10,800	9,389
Maintenance	**6,633**	6,728	5,190
Depreciation and amortization	**15,304**	16,187	16,059
Taxes other than income	**7,402**	7,295	7,242
Income taxes	**(691)**	1,242	(1,367)
Total operating expenses	**272,066**	243,102	178,832
Operating income	**5,260**	7,946	5,472
Other Income			
Equity in earnings of affiliates and non-utility operations	**2,495**	2,919	2,058
Allowance for equity funds used during construction	**284**	134	104
Other income and deductions, net	**(73)**	400	(549)
Total other income	**2,706**	3,453	1,613
Income before interest charges	**7,966**	11,399	7,085
Interest Charges			
Long-term debt	**6,499**	6,716	6,991
Other	**986**	558	1,016
Allowance for borrowed funds used during construction	**(228)**	(91)	(131)
Total interest charges	**7,257**	7,183	7,876
Income (loss) before preferred dividends and discontinued operations	**709**	4,216	(791)
Dividends on preferred stock	**1,014**	1,155	1,296
Income (loss) from continuing operations	**(305)**	3,061	(2,087)
Net income (loss) from discontinued segment operations	**—**	(603)	(2,086)
Loss on disposal, including provisions for operating losses during phaseout period	**(6,549)**	(6,676)	—
Net Income (Loss) Applicable to Common Stock	**($ 6,854)**	($ 4,218)	($ 4,173)
Common Stock Data			
Basic and diluted earnings per share from discontinued operations	**($ 1.19)**	($ 1.36)	($ 0.40)
Basic and diluted earnings per share from continuing operations	**(0.06)**	0.57	(0.40)
Basic and diluted earnings per share	**($ 1.25)**	($ 0.79)	($ 0.80)
Cash dividends declared per share	**$ 0.55**	$ 0.55	$ 0.96
Weighted average shares outstanding	**5,491**	5,361	5,243

1997	1996	1995	1994	1993	1992	1991	1990
$ 61,423	$ 60,598	$ 55,434	$ 50,966	$ 49,391	$ 45,658	$ 42,298	$ 40,636
—	—	—	—	419	1,883	2,181	2,173
61,423	60,598	55,434	50,966	49,810	47,541	44,479	42,809
58,700	56,530	51,245	48,374	47,310	45,552	43,030	40,596
37,841	36,704	32,616	31,381	31,569	31,775	29,721	27,569
17,847	20,667	17,541	13,521	14,441	17,258	23,663	34,777
3,512	4,510	4,708	3,955	4,123	3,114	2,662	1,882
179,323	179,009	161,544	148,197	147,253	145,240	143,555	147,633
32,817	30,596	30,222	30,300	29,785	29,230	27,464	28,116
5,327	3,330	3,786	3,113	3,150	3,804	4,946	4,688
62,222	66,320	53,915	45,777	46,066	41,878	45,951	53,590
16,780	17,615	18,120	17,296	17,353	17,239	15,934	16,037
11,122	10,833	9,874	10,374	10,775	11,103	11,661	11,032
4,785	4,463	4,210	4,465	4,352	4,692	4,340	4,377
16,359	16,280	14,116	10,683	8,572	8,065	7,046	6,754
7,205	6,982	6,428	6,277	6,125	5,902	5,677	4,361
7,191	6,463	5,578	5,395	6,249	6,915	6,022	4,970
163,808	162,882	146,249	133,680	132,427	128,828	129,041	133,925
15,515	16,127	15,295	14,517	14,826	16,412	14,514	13,708
285	1,564	2,131	2,287	2,239	2,305	2,888	2,758
357	175	27	263	273	186	225	86
789	175	94	306	19	(105)	(66)	(553)
1,431	1,914	2,252	2,856	2,531	2,386	3,047	2,291
16,946	18,041	17,547	17,373	17,357	18,798	17,561	15,999
7,274	6,872	6,546	6,868	6,539	6,542	6,064	5,769
691	994	1,427	867	646	479	1,039	1,490
(315)	(468)	(547)	(539)	(357)	(202)	(131)	(394)
7,650	7,398	7,426	7,196	6,828	6,819	6,972	6,865
9,296	10,643	10,121	10,177	10,529	11,979	10,589	9,134
1,433	1,010	771	794	811	831	852	421
7,863	9,633	9,350	9,383	9,718	11,148	9,737	8,713
142	1,316	1,382	825	102	(127)	(133)	(168)
—	—	—	—	—	—	—	—
$ 8,005	$ 10,949	$ 10,732	$ 10,208	$ 9,820	$ 11,021	$ 9,604	$ 8,545
$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02	($ 0.03)	($ 0.03)	($ 0.05)
1.54	1.95	1.97	2.05	2.18	2.57	2.48	2.34
$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20	$ 2.54	$ 2.45	$ 2.29
$ 1.61	$ 2.12	$ 2.12	$ 2.12	$ 2.11	$ 2.08	$ 2.04	$ 2.00
5,112	4,933	4,747	4,588	4,457	4,345	3,919	3,729

Consolidated Balance Sheets

GREEN MOUNTAIN POWER CORPORATION • At December 31

Dollars in thousands	2000	1999	1998
Assets			
Utility plant, at original cost	**$291,107**	$283,917	$276,853
Less accumulated depreciation	**110,273**	102,854	94,604
Net utility plant	**180,834**	181,063	182,249
Property under capital lease	**6,449**	7,038	7,696
Construction work in progress	**7,389**	4,795	5,611
Total utility plant, net	**194,672**	192,896	195,556
Associated companies, at equity	**14,373**	14,545	15,048
Other investments	**6,357**	6,120	5,630
Current assets	**53,652**	33,238	35,700
Deferred charges	**46,036**	43,296	35,576
Non-Utility			
Current assets	**8**	48	7,974
Property and equipment	**252**	253	1,213
Business segment held for disposal	**—**	9,477	—
Other assets	**1,258**	1,321	18,127
Total non-utility assets	**1,518**	11,099	27,314
Total assets	**$316,608**	$301,194	$314,824
Capitalization and Liabilities			
Capitalization			
Common stock equity			
Common stock	**$ 18,608**	$ 18,085	$ 17,711
Additional paid-in capital	**73,321**	72,594	71,914
Retained earnings	**493**	10,344	17,508
Treasury stock, at cost	**(378)**	(378)	(378)
Total common stock equity	**92.044**	100,645	106,755
Redeemable cumulative preferred stock	**12,795**	14,435	16,085
Long-term debt, less current maturities	**72,100**	81,800	88,500
Total capitalization	**176,939**	196,880	211,340
Capital lease obligation	**6,449**	7,038	7,696
Current liabilities	**68,109**	38,150	28,825
Accumulated deferred income taxes	**25,644**	25,201	23,389
Unamortized investment tax credits	**3,695**	3,978	4,260
Pine Street Barge Canal site cleanup	**11,554**	8,815	11,220
Deferred credits and other	**20,901**	21,132	21,020
Non-Utility			
Current liabilities	**—**	—	720
Other liabilities	**3,317**	—	6,354
Total non-utility liabilities	**3,317**	—	7,074
Total capitalization and liabilities	**$316,608**	$301,194	$314,824

Consolidated Statements of Retained Earnings

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2000	1999	1998
Balance at beginning of year	**$10,344**	$17,508	$26,717
Net income (loss)	**(5,840)**	(3,063)	(2,878)
	4,504	14,445	23,839
Deduct cash dividends declared			
Redeemable cumulative preferred stock	**1,014**	1,155	1,296
Common stock	**2,997**	2,946	5,035
Total	**4,011**	4,101	6,331
Balance at year end	**$ 493**	$10,344	$17,508

1997	1996	1995	1994	1993	1992	1991	1990
$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179	$182,293
87,689	81,286	75,797	69,246	64,226	58,516	55,658	51,354
177,752	166,849	163,494	158,745	150,751	143,127	138,521	130,939
8,342	9,006	9,778	10,278	11,029	11,950	12,627	12,797
10,626	13,998	8,727	6,964	9,631	9,646	8,582	8,634
196,720	189,853	181,999	175,987	171,411	164,723	159,730	152,370
15,860	15,769	16,024	16,684	16,886	17,139	17,798	17,988
6,137	4,865	4,224	4,067	5,642	4,561	3,826	1,797
29,125	30,901	30,216	28,798	26,215	28,067	26,778	25,891
35,831	43,224	42,951	35,659	33,893	19,012	11,271	10,536
11,654	4,490	4,131	6,295	3,656	5,016	3,233	1,631
10,784	11,226	11,478	11,329	11,331	10,589	7,971	3,246
—	—	—	—	—	—	—	—
19,622	24,211	22,259	15,792	13,639	8,111	8,628	6,201
42,060	39,927	37,868	33,416	28,626	23,716	19,832	11,078
$325,733	$324,539	$313,282	$294,611	$282,673	$257,218	$239,235	$219,660

$ 17,318	$ 16,790	$ 16,168	$ 15,592	$ 15,120	$ 14,712	$ 14,359	$ 12,599
70,720	68,226	64,206	60,378	57,178	53,510	50,668	38,438
26,717	26,916	26,412	25,727	25,229	24,801	22,806	21,187
(378)	(378)	(378)	(378)	(378)	(378)	(378)	(282)
114,377	111,554	106,408	101,319	97,149	92,645	87,455	71,942
17,735	19,310	8,930	9,135	9,385	9,575	9,825	10,087
93,200	94,900	91,134	74,967	79,800	67,644	56,270	60,626
225,312	225,764	206,472	185,421	186,334	169,864	153,550	142,655
8,342	9,006	9,778	10,278	11,029	11,950	12,627	12,797
25,286	21,037	32,629	40,441	37,925	30,099	32,893	32,399
23,501	26,726	25,292	22,082	21,001	15,504	12,415	10,941
4,542	4,825	5,107	5,390	5,672	5,955	6,240	6,470
—	—	—	—	—	—	—	—
25,680	23,417	21,642	21,962	13,541	11,805	11,039	9,947
1,119	1,752	1,124	918	666	3,524	2,353	84
11,951	12,012	11,238	8,119	6,505	8,517	8,118	4,367
13,070	13,764	12,362	9,037	7,171	12,041	10,471	4,451
$325,733	$324,539	$313,282	$294,611	$282,673	$257,218	$239,235	$219,660

1997	1996	1995	1994	1993	1992	1991	1990
$26,916	$26,412	$25,727	$25,229	$24,801	$22,806	$21,187	$20,206
9,438	11,959	11,503	11,002	10,631	11,852	10,456	8,966
36,354	38,371	37,230	36,231	35,432	34,658	31,643	29,172
1,433	1,010	771	794	811	831	852	421
8,204	10,445	10,047	9,710	9,392	9,026	7,985	7,564
9,637	11,455	10,818	10,504	10,203	9,857	8,837	7,985
$26,717	$26,916	$26,412	$25,727	$25,229	$24,801	$22,806	$21,187

Consolidated Statements of Cash Flows

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2000	1999	1998
		(In thousands)	
Operating Activities:			
Net income (loss)	**($ 5,840)**	($ 3,063)	($ 2,878)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**15,304**	16,187	16,059
Dividends from associated companies less equity income	**(26)**	169	812
Allowance for funds used during construction	**(512)**	(224)	(235)
Amortization of purchased power costs	**5,575**	5,725	6,405
Deferred income taxes	**443**	1,812	(112)
Provision for loss on disposal of business segment	**6,549**	6,676	—
Accrued purchase power option call	**8,276**	—	—
Deferred purchased power costs	**(6,692)**	(6,590)	(7,830)
Investment tax credits, net	**(282)**	(282)	(282)
Provision for chargeoff of deferred regulatory asset	**3,229**	—	—
Environmental proceedings and conservation expenditures	**(2,073)**	(8,048)	1,177
Changes in current assets and current liabilities	**(9,628)**	4,751	(3,822)
Other	**(3,364)**	(2,008)	645
Net cash provided by operating activities	**10,959**	15,105	9,939
Net cash provided (used) by discontinued segment	**245**	(138)	—
Net cash provided by operating activities	**11,204**	14,967	9,939
Investing Activities:			
Construction expenditures	**(13,853)**	(9,174)	(10,900)
Investment in non-utility property	**(187)**	(190)	(1,442)
Proceeds from sale of subsidiaries	**6,000**	—	11,500
Investment in associated companies	**—**	—	—
Special fund for postretirement benefits	**—**	—	—
Net cash used in investing activities	**(8,040)**	(9,364)	(842)
Financing Activities:			
Investment in certificate pledged	**(15,437)**	—	—
Issuance of preferred stock	**—**	—	—
Reduction in preferred stock	**(1,640)**	(1,650)	(1,650)
Energy East obligation	**15,419**	—	—
Issuance of common stock	**1,250**	1,054	1,587
Short-term debt, net	**7,600**	900	4,384
Issuance of long-term debt	**—**	—	—
Reduction in long-term debt	**(6,700)**	(1,700)	(6,767)
Cash dividends	**(4,011)**	(4,101)	(6,332)
Net cash provided by (used in) financing activities	**(3,519)**	(5,497)	(8,778)
Net increase (decrease) in cash and cash equivalents	**(355)**	106	319
Cash and cash equivalents at beginning of year	**696**	590	271
Cash and Cash Equivalents at End of Year	**$ 341**	$ 696	$ 590

1997	1996	1995	1994	1993	1992	1991	1990
$ 9,438	$ 11,959	$ 11,503	$ 11,002	$ 10,631	$ 11,852	$ 10,456	$ 8,966
16,359	16,280	14,116	10,683	8,572	8,065	7,046	6,754
(90)	254	660	202	254	659	190	298
(672)	(643)	(574)	(803)	(630)	(388)	(356)	(480)
5,212	5,187	6,036	4,178	3,723	3,825	1,840	3,679
(2,715)	1,937	3,715	1,585	5,180	3,089	1,474	2,245
—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
(331)	(5,917)	(12,935)	(536)	(6,432)	(5,347)	104	(5,035)
(282)	(282)	(283)	(283)	(283)	(284)	(230)	(481)
—	—	—	—	—	—	—	—
(4,534)	(4,927)	(5,311)	715	(10,608)	(5,618)	(2,374)	(1,618)
(2,517)	781	(595)	(4,220)	1,221	(577)	(1,385)	(3,420)
6,230	1,738	(95)	2,383	(1,936)	44	4,380	(1,398)
26,098	26,367	16,237	24,906	9,692	15,320	21,145	9,510
—	—	—	—	—	—	—	—
26,098	26,367	16,237	24,906	9,692	15,320	21,145	9,510
(16,409)	(17,541)	(15,314)	(13,536)	(15,949)	(15,327)	(19,475)	(14,358)
218	(2,203)	(6,121)	(1,220)	(5,950)	(282)	(2,305)	107
—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	(374)
—	—	—	—	(601)	(56)	(1,463)	—
(16,191)	(19,744)	(21,435)	(14,756)	(22,500)	(15,665)	(23,243)	(14,625)
—	—	—	—	—	—	—	—
—	12,000	—	—	—	—	—	7,000
(1,575)	(1,620)	(205)	(250)	(190)	(250)	(262)	(287)
—	—	—	—	—	—	(96)	—
3,428	4,642	4,404	3,671	4,077	3,195	13,893	1,502
1,600	(7,400)	(11,799)	1,198	7,402	(2,093)	2,302	(2,882)
—	14,000	25,917	—	20,000	17,000	—	9,000
(4,201)	(16,201)	(4,833)	(1,800)	(8,530)	(7,246)	(5,116)	(1,566)
(9,637)	(11,455)	(10,818)	(10,504)	(10,204)	(9,857)	(8,837)	(7,985)
(10,385)	(6,034)	2,666	(7,685)	12,555	749	1,980	4,782
(478)	589	(2,532)	2,465	(253)	404	(118)	(333)
749	160	2,692	227	480	76	194	527
$ 271	$ 749	$ 160	$ 2,692	$ 227	$ 480	$ 76	$ 194

Common Stock Data and Stock Ratios

GREEN MOUNTAIN POWER CORPORATION • At and for the Years Ended December 31

		2000	1999	1998
Common Stock Data				
Net income (loss) applicable to Common stock (in thousands)	($)	**(6,854)**	(4,218)	(4,173)
Shares outstanding (in thousands and net of treasury shares)				
Year-end		**5,567**	5,410	5,297
Weighted average		**5,491**	5,361	5,243
Per share of Common stock				
Earnings (loss) per average share (Note 1)	($)	**(1.25)**	(0.79)	(0.80)
Dividends paid	($)	**0.55**	0.55	0.9625
Payout ratio (Note 5)	(%)	—	—	—
Net book value	($)	**16.53**	18.60	20.15
Price range N.Y.S.E.				
High	($)	**12-13/16**	14	20-1/16
Low	($)	**6-7/8**	7-1/8	10-1/16
Year-end	($)	**12-1/2**	7-7/16	10-1/2
Price Earnings Ratio (price at year-end) (Note 5)		—	—	—
Capitalization (in thousands)				
Common stock equity	($)	**92,044**	100,645	106,755
Redeemable cumulative preferred stock	($)	**12,795**	14,435	16,085
Long-term debt (including current maturities)	($)	**81,800**	88,500	90,200
Total	($)	**186,639**	203,580	213,040
Capitalization Ratios				
Common stock equity	(%)	**49.3**	49.4	50.1
Redeemable cumulative preferred stock	(%)	**6.9**	7.1	7.6
Long-term debt (including current maturities)	(%)	**43.8**	43.5	42.3
Total	(%)	**100.0**	100.0	100.0
Other Financial Ratios				
Long-term debt weighted average annual interest rate	(%)	**7.5**	7.5	7.6
Preferred stock weighted average annual dividend rate	(%)	**7.5**	7.5	7.5
Income before interest and income taxes to long-term debt interest		**0.1**	0.8	0.5
Income before interest and after income taxes to long-term debt interest		**0.2**	0.6	0.7
Income before interest and after income taxes to total interest charges and preferred dividends		**0.2**	0.5	0.5
Operating revenues as a % of net utility property (year-end) (Note 2)	(%)	**132.7**	115.2	80.7
Operating expenses (excluding income taxes) as a % of operating revenues	(%)	**98.4**	96.3	97.8
Annual depreciation expense as a % of depreciable property	(%)	**3.5**	3.3	3.4
Accumulated depreciation as a % of depreciable property	(%)	**37.9**	36.2	36.2
Return on average common equity (Note 3)	(%)	**(7.1)**	(4.0)	(3.8)
Internally generated funds as a % of capital requirements, sinking fund obligations and other requirements (Note 4)	(%)	**59.4**	89.0	64.6
AFUDC as a % of net income (loss) applicable to common stock	(%)	**(7.5)**	(5.3)	(5.6)

NOTES:
(1) Based on weighted average number of shares outstanding during each year, excluding number of shares held in treasury.
(2) Includes investment in associated companies.
(3) Average common equity is computed using a thirteen-month average.
(4) Internally generated funds are net of dividend payments.
(5) Measure is not meaningful for years with net loss.

1997	1996	1995	1994	1993	1992	1991	1990
8,005	10,949	10,732	10,208	9,820	11,021	9,604	8,545
5,180	5,021	4,835	4,662	4,520	4,398	4,292	3,768
5,112	4,933	4,747	4,588	4,457	4,345	3,919	3,729
1.57	2.22	2.26	2.23	2.20	2.54	2.45	2.29
1.61	2.12	2.12	2.12	2.11	2.08	2.04	2.00
102.5	95.5	93.8	95.1	95.9	81.9	83.3	87.3
22.08	22.22	22.01	21.73	21.49	21.07	20.38	19.09
26-1/4	29-1/8	28-5/8	31-1/4	36-5/8	33-5/8	30-1/4	27-1/8
17-5/8	22-3/4	23-7/8	23-3/8	30-3/4	29	22	21-1/4
18-3/8	23-7/8	27-3/4	27-7/8	31	33-1/8	29-7/8	22-1/4
12	11	12	13	14	13	12	10
114,377	111,554	106,408	101,319	97,149	92,645	87,455	71,942
17,735	19,310	8,930	9,135	9,385	9,575	9,825	10,087
94,900	97,934	98,967	79,800	81,600	70,130	60,376	65,492
227,012	228,798	214,305	190,254	188,134	172,350	157,656	147,521
50.4	48.8	49.7	53.3	51.6	53.7	55.5	48.8
7.8	8.4	4.2	4.8	5.0	5.6	6.2	6.8
41.8	42.8	46.1	41.9	43.4	40.7	38.3	44.4
100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
7.7	8.1	9.0	8.7	9.4	9.8	10.2	9.7
7.6	8.8	8.5	8.5	8.5	8.5	8.5	7.4
3.3	3.8	3.7	3.4	3.6	3.9	3.9	3.6
2.3	2.8	2.9	2.6	2.7	2.9	2.9	2.7
1.9	2.3	2.3	2.3	2.3	2.4	2.2	2.2
75.1	78.9	73.4	69.5	71.4	75.4	77.1	84.2
87.3	87.4	87.1	86.6	85.7	83.9	85.7	87.3
3.2	3.3	3.3	3.2	3.2	3.2	3.2	3.2
34.9	34.5	33.8	32.4	31.8	30.8	32.0	30.4
7.1	10.0	10.3	10.3	10.3	12.2	12.5	12.0
129.4	38.8	58.0	83.7	46.2	50.3	40.9	49.0
8.4	5.9	5.3	7.9	6.4	3.5	3.7	5.6

Employees, Plant Investment, Sales of Securities

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands	2000	1999	1998
Number of Active Employees full and part time, at December 31,			
—Green Mountain Power	**197**	196	288
—Subsidiaries	**5**	5	6
Utility Plant Investment (year-end)			
Intangible	**$ 11,726**	$ 11,276	$ 10,206
Steam production	**10,525**	10,460	10,782
Hydro production	**29,728**	29,667	29,435
Other production	**21,833**	22,141	22,217
Transmission	**35,100**	34,793	34,924
Distribution	**157,959**	151,873	145,694
General	**24,236**	23,707	23,595
Total utility plant investment	**291,107**	283,917	276,853
Less accumulated depreciation	**110,273**	102,854	94,604
Net utility plant	**180,834**	181,063	182,249
Property under capital lease	**6,449**	7,038	7,696
Construction work in progress	**7,389**	4,794	5,611
Total utility plant investment, net	**$194,672**	$192,895	$195,556
Beginning balance—utility plant	**$283,917**	$276,853	$265,441
Transfers to utility plant from CWIP	**11,258**	9,990	15,927
Retirements from utility plant	**(4,068)**	(2,926)	(4,515)
Ending balance—utility plant	**$291,107**	$283,917	$276,853
Beginning balance—construction work in progress	**$ 4,794**	$ 5,611	$ 10,626
Construction expenditures, net of customer advances	**13,853**	9,173	10,912
Transfers to utility plant	**(11,258)**	(9,990)	(15,927)
Ending balance—construction work in progress	**$ 7,389**	$ 4,794	$ 5,611
Sales of Securities (gross proceeds)			
Long-term debt	**$ —**	$ —	$ —
Common stock (excludes DRIP, ESIP, PAYSOP, restricted shares and stock grants)	**—**	—	—
Redeemable cumulative preferred stock	**—**	—	—
Total sales of securities	**$ —**	$ —	$ —

1997	1996	1995	1994	1993	1992	1991	1990
321	344	350	373	387	388	392	392
48	45	50	59	58	82	73	27
$ 9,168	$ 6,330	$ 7,451	$ 6,415	$ 4,571	$ 3,126	$ 4,582	$ 3,336
10,702	10,702	10,799	10,752	10,748	10,688	10,679	10,646
29,200	28,771	26,315	25,757	24,930	24,034	23,820	20,893
22,862	18,239	18,393	18,427	18,402	17,533	17,482	17,759
33,878	30,356	29,837	29,344	28,698	25,623	25,335	23,935
136,825	131,626	124,330	116,325	107,489	101,367	94,142	88,036
22,806	22,111	22,166	20,971	20,139	19,272	18,139	17,688
265,441	248,135	239,291	227,991	214,977	201,643	194,179	182,293
87,689	81,286	75,797	69,246	64,226	58,516	55,658	51,354
177,752	166,849	163,494	158,745	150,751	143,127	138,521	130,939
8,342	9,006	9,778	10,278	11,029	11,950	12,627	12,797
10,626	13,998	8,727	6,964	9,631	9,646	8,582	8,634
$196,720	$189,853	$181,999	$175,987	$171,411	$164,723	$159,730	$152,370
$248,135	$239,291	$227,991	$214,977	$201,643	$194,179	$182,293	$169,053
20,222	12,522	13,403	16,204	15,223	11,644	16,839	15,686
(2,916)	(3,678)	(2,103)	(3,190)	(1,889)	(4,180)	(4,953)	(2,446)
$265,441	$248,135	$239,291	$227,991	$214,977	$201,643	$194,179	$182,293
$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646	$ 8,582	$ 8,634	$ 9,986
16,850	17,793	15,166	13,537	15,208	12,708	16,787	14,334
(20,222)	(12,522)	(13,403)	(16,204)	(15,223)	(11,644)	(16,839)	(15,686)
$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646	$ 8,582	$ 8,634
$ —	$ 14,000	$ 24,000	$ —	$ 20,000	$ 17,000	$ —	$ 9,000
—	—	—	—	—	—	12,136	—
—	12,000	—	—	—	—	—	7,000
$ —	$ 26,000	$ 24,000	$ —	$ 20,000	$ 17,000	$ 12,136	$ 16,000

Power Supply Statistics, Electric Sales

GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

	2000	1999	1998
Net System Capability During Peak Month (MW*)			
Total capability (MW)	**411.1**	393.2	396.9
Net system peak	**323.5**	317.9	312.5
Reserve (MW)	**87.6**	75.3	84.4
Reserve % of peak	**27.1%**	23.7%	27.0%
Net Production (MWH)**			
Hydro	**1,053,223**	1,095,738	972,723
Lease transmissions	**—**	—	—
Nuclear	**803,303**	731,431	607,708
Conventional steam	**2,704,427**	2,328,267	750,602
Internal combustion	**35,699**	12,312	40,148
Combined cycle	**73,433**	99,962	118,322
Wind	**12,246**	7,956	—
Total production	**4,682,331**	4,275,666	2,489,503
Less nonrequirements sales to other utilities	**2,573,576**	2,152,781	499,409
Production for requirements sales	**2,108,755**	2,122,885	1,990,094
Less requirements sales and lease transmissions (MWH)	**1,954,898**	1,920,257	1,883,959
Losses and Company use (MWH)	**153,857**	202,628	106,134
Losses as a % of total production	**3.29%**	4.74%	4.26%
System load factor (***)	**68.8%**	80.3%	71.8%
Sales and Lease Transmissions (MWH)**			
Residential—GMP	**558,682**	544,447	533,904
Lease MWH transmitted	**—**	—	—
Total Residential	**558,682**	544,447	533,904
Commercial & industrial–small	**704,126**	688,493	665,707
Commercial & industrial–large	**683,296**	664,110	636,436
Other	**6,713**	3,138	3,476
Total retail sales and lease transmissions	**1,952,817**	1,900,188	1,839,522
Sales to Municipals & Cooperatives (Rate W)	**2,081**	20,069	44,437
Total Requirements Sales	**1,954,898**	1,920,257	1,883,959
Other Sales for Resale	**2,573,576**	2,152,781	499,409
Total sales and lease transmissions	**4,528,474**	4,073,038	2,383,368
Average Number of Electric Customers			
Residential	**72,424**	71,515	71,301
Commercial & industrial–small	**12,746**	12,438	12,170
Commercial & industrial–large	**23**	23	23
Other	**65**	66	70
Total	**85,258**	84,042	83,564
Average Revenue Per KWH (Cents)			
Residential including lease revenues	**12.50**	12.32	11.56
Lease charges	**—**	—	—
Total Residential	**12.50**	12.32	11.56
Commercial & industrial–small	**10.00**	9.88	9.29
Commercial & industrial–large	**6.51**	6.55	6.32
Total retail including lease revenues	**9.52**	9.47	8.96
Average Use and Revenue Per Residential Customer			
KWH including lease transmissions	**7,717**	7,617	7,488
Revenues including lease revenues	**$965**	$938	$865

*MW—Megawatt is one thousand kilowatts.

**MWH—Megawatthour is one thousand kilowatthours.

1997	1996	1995	1994	1993	1992	1991	1990
416.9	425.8	396.1	438.2	474.7	439.9	415.1	381.5
311.5	313.0	297.1	308.3	307.3	314.4	308.5	301.9
105.4	112.8	99.0	129.9	167.4	125.5	106.6	79.6
33.8%	36.0%	33.3%	42.1%	54.5%	39.9%	34.6%	26.4%
1,073,246	1,192,881	1,043,617	742,088	751,078	641,525	611,658	784,358
—	—	—	—	15,425	58,374	67,600	66,235
772,030	680,613	682,814	763,690	598,245	665,034	731,582	671,563
560,504	705,331	673,982	651,105	748,626	762,451	799,781	859,059
4,827	2,674	6,646	3,532	2,849	1,504	3,809	1,176
104,836	51,162	92,723	37,808	40,966	60,138	104,344	90,825
—	—	—	—	—	—	—	—
2,515,443	2,632,661	2,499,782	2,198,223	2,157,189	2,189,026	2,318,774	2,473,216
524,192	663,175	582,942	328,794	271,224	273,087	448,110	587,475
1,991,251	1,969,486	1,916,840	1,869,429	1,885,965	1,915,939	1,870,664	1,885,741
1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986	1,742,308	1,759,393
120,338	155,115	156,010	138,932	136,511	120,953	128,356	126,348
4.78%	5.89%	6.24%	6.32%	6.33%	5.53%	5.54%	5.11%
71.6%	69.7%	71.2%	67.7%	68.7%	68.5%	67.9%	69.5%
549,259	557,726	549,296	564,635	541,579	505,234	483,998	500,163
—	—	—	—	15,425	58,374	67,600	67,370
549,259	557,726	549,296	564,635	557,004	563,608	551,598	567,533
645,331	630,839	608,688	604,686	593,560	582,594	571,818	580,562
608,051	584,249	556,278	521,400	529,372	539,665	519,201	519,688
3,939	2,898	8,855	1,146	8,868	6,312	2,770	(4,726)
1,806,580	1,775,712	1,723,117	1,691,867	1,688,804	1,692,179	1,645,387	1,663,057
64,333	38,659	37,713	38,630	60,650	102,807	96,921	96,335
1,870,913	1,814,371	1,760,830	1,730,497	1,749,454	1,794,986	1,742,308	1,759,392
524,192	663,175	582,942	328,794	271,224	273,087	448,110	587,474
2,395,105	2,477,546	2,343,772	2,059,291	2,020,678	2,068,073	2,190,418	2,346,866
70,671	70,198	69,659	68,811	67,994	67,201	66,406	65,553
11,989	11,828	11,712	11,611	11,447	11,245	11,215	11,300
23	25	24	24	25	24	24	23
75	75	76	76	74	73	71	71
82,758	82,126	81,471	80,522	79,540	78,543	77,716	76,947
11.18	10.87	10.09	9.03	8.94	8.44	8.06	7.54
—	—	—	—	.06	.41	.26	.25
11.18	10.87	10.09	9.03	9.00	8.85	8.32	7.79
9.10	8.96	8.42	8.00	7.97	7.82	7.53	6.99
6.22	6.28	5.86	6.02	5.96	5.89	5.72	5.30
8.79	8.72	8.36	7.96	7.86	7.56	7.29	6.79
7,772	7,945	7,885	8,206	8,192	8,387	8,306	8,658
$869	$863	$796	$741	$733	$707	$670	$653

***Load factor is based on net system peak and firm MWH production less off-system losses.

Shareholder Information

CONTACTS:

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(802)864-5731

Corporate Secretary:	Nancy Rowden Brock (802)655-8451 e-mail: brock@gmpvt.com
Investor Relations and Shareholder Services:	Gayle Mckinnon-Alexander Manager, Investor Relations (802)655-8455 e-mail: mckinnon@gmpvt.com
News Media Inquiries:	Dorothy A. Schnure Manager, Corporate Communications (802)655-8418 e-mail: schnure@gmpvt.com
Internet:	www.gmpvt.com

INVESTOR RELATIONS:

Transfer Agent and Registrar:	ChaseMellon Shareholder Services, L.L.C. e-mail: www.chasemellon.com (800)851-9677
Shareholder services involving stock transfers, lost certificates, dividend problems, address changes or dividend reinvestment:	ChaseMellon Shareholder Services, L.L.C. Overpeck Centre 85 Challenger Road Ridgefield Park, NJ 07660 (800)851-9677

Annual Report on Form 10-K

A copy of the 2000 Annual Report on Form 10-K filed with the Securities and Exchange Commission is available upon request to the Manager, Investor Relations.

Common Stock Listing:
New York Stock Exchange
Symbol: GMP

Dividend Schedule for 2001 (approximate)

Record Dates	Payment Dates
Mid-March	March 30
Mid-June	June 29
Mid-September	September 28
Mid-December	December 31

Bond Ratings as of March 5, 2001 (See page 20 for details)

	Fitch	Moody's	S&P
First Mortgage Bonds	BB+	Baa2	BBB
Preferred Stock	B+	baa3	BB

Dividend Reinvestment and Stock Purchase Plan

GMP offers a Dividend Reinvestment and Stock Purchase Plan that provides a low-cost way for shareholders of record and Vermont residents to purchase additional shares of common stock directly from the Company through optional investments and reinvested dividends. The price of common stock purchased with reinvested dividends will be at a 5% discount. Participants in the Plan may make optional cash investments of $50 per investment, not to exceed $40,000 per year. The transfer agent must receive the investment at least five business days prior to month-end, since optional cash investments are made the last business day of each month. The plan also offers safekeeping of certificate shares. Prospectuses and authorization forms may be obtained from the Company or the transfer agent.

Transferring Stock

A stock transfer is required whenever there is a change in the name or names in which the stock certificate is registered. This can happen when you sell the stock, make a gift of stock, or add or delete owners of the certificate. To transfer your stock, fill in the name, address and taxpayer identification number on the back of your certificate and sign your name exactly as it appears on the front. Your signature must be guaranteed by a commercial bank, or a brokerage firm that is a member of a major stock exchange. Your certificate, fully endorsed, should be sent to the transfer agent by registered or certified mail.

Replacement of Dividend Checks

If you do not receive your dividend check within 10 business days after the dividend payment date, or if your check becomes lost or destroyed, you should notify the transfer agent so payment may be stopped and a replacement check issued.

Lost or Stolen Certificates

Stock certificates are valuable pieces of paper that should be kept in a safe place. If your stock certificate is lost, destroyed or stolen, please notify the transfer agent immediately so that a "stop transfer" can be placed on the missing certificate. The transfer agent will send you the necessary documents to obtain a replacement certificate. There is a charge for certificate replacements.

Duplicate Mailings and Multiple Dividend Checks

Some shareholders maintain several accounts with slight variation in the registered ownership (John A. Smith, J.A. Smith, or John A. Smith and Mary K. Smith). Even though the mailing address is identical, we are required by law to create a separate account for each name and to mail separate dividend checks, annual reports and proxy material to each account.

If you want to maintain separate accounts but eliminate duplicate mailings of annual reports, simply write to the transfer agent and list the account(s) for which mailings should continue or be discontinued. Dividend checks and proxy materials will still be sent to each account.

If you would like to consolidate your accounts, write to the transfer agent stating which account you want to remain open and which ones you want consolidated. It may be necessary to reissue stock certificates.

2001 Annual Shareholders Meeting

All shareholders are invited to attend GMP's Annual Meeting on Thursday, May 17, 2001 at the Sheraton Hotel and Conference Center, 870 Williston Road, South Burlington, Vermont. The meeting will begin at 10 a.m.