Green Mountain Power Report to Shareholders

2003

Financial and Operating Highlights

	2003	2002	2001
Financial Data			
Operating revenues	**$280,470,000**	$274,608,000	$283,464,000
Operating expenses	**$265,164,000**	$259,528,000	$267,005,000
Net income (loss), continuing operations	**$ 10,325,000**	$ 11,299,000	$ 10,860,000
Net income (loss), discontinued operations	**$ 79,000**	$ 99,000	($ 182,000)
Net income (loss) applicable to common stock	**$ 10,401,000**	$ 11,302,000	$ 10,678,000
Total utility plant	**$324,901,000**	$311,543,000	$302,489,000
Common Share Data			
Weighted average shares outstanding	**4,980,000**	5,592,000	5,630,000
Year-end shares outstanding	**5,033,000**	4,955,000	5,685,000
Diluted earnings (loss) per average share, continuing operations	**$ 2.01**	$ 1.96	$ 1.88
Diluted earnings (loss) per average share, discontinued operations	**$ 0.01**	$ 0.02	($ 0.03)
Diluted earnings (loss) per average share	**$ 2.02**	$ 1.98	$ 1.85
Dividends paid per share	**$ 0.76**	$ 0.60	$ 0.55
Year-end book value per share	**$19.85**	$18.51	$17.81
Dividend yield on ending market value	**2.55%**	2.87%	2.95%
Return on average common equity	**10.80%**	11.03%	11.02%
Operating Data			
Electric customers—year-end	**89,000**	88,000	87,000
Retail and requirements sales (MWH)	**1,934,000**	1,952,000	1,956,000
Other sales for resale (MWH)	**2,287,000**	2,104,000	2,365,000
Average revenue per kWh (cents)	**10.22**	10.09	10.44
Number of Employees—Year-End			
Green Mountain Power	**196**	194	193
Subsidiaries	**0**	0	0

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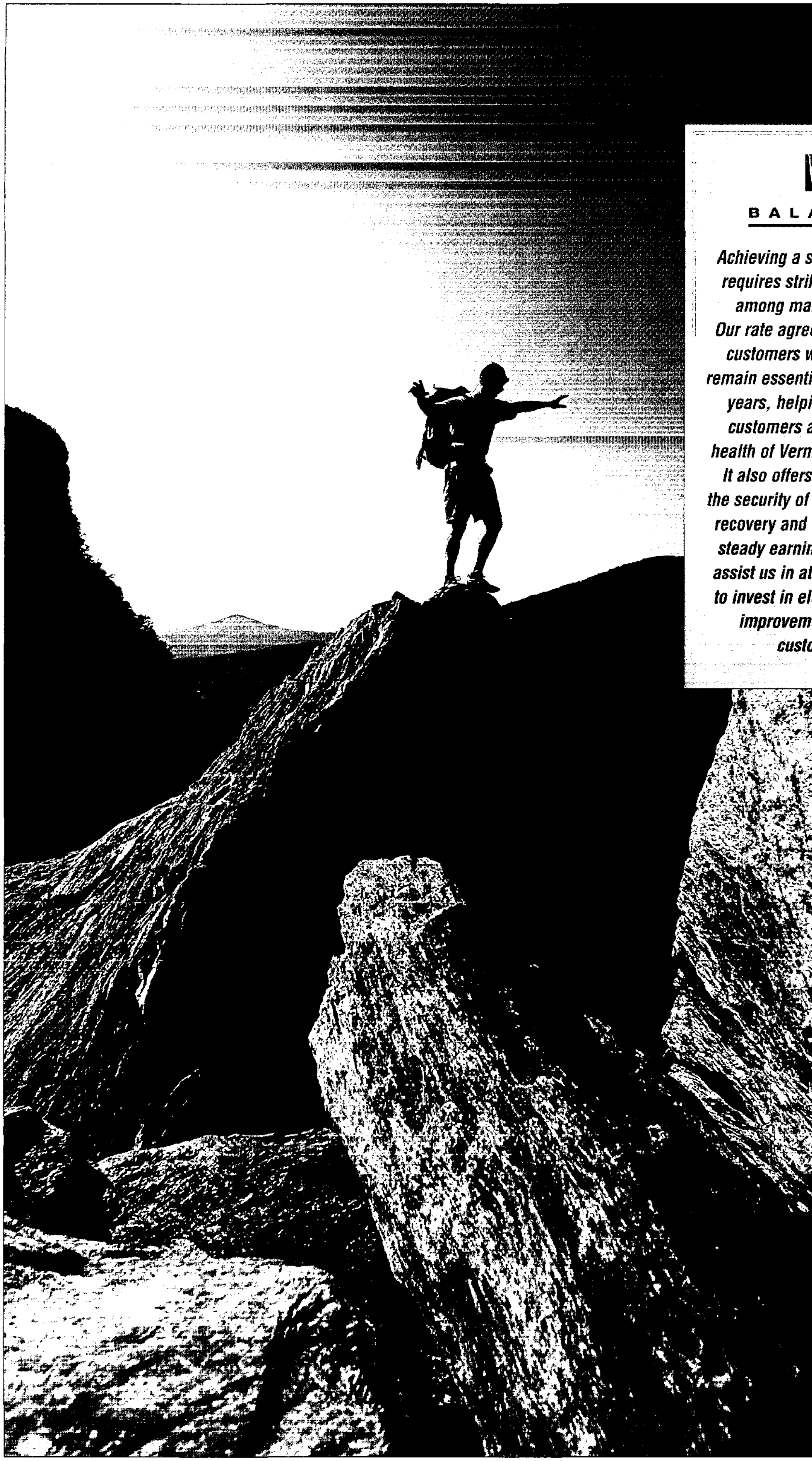
It is the policy of Green Mountain Power to provide equal employment opportunities to all qualified employees and applicants. Through its affirmative action plan and affirmative action efforts, GMP ensures that the policy is enforced.



BALANCE

Achieving a stable rate plan requires striking a balance among many interests. Our rate agreement provides customers with rates that remain essentially flat over six years, helping individual customers as well as the health of Vermont's economy. It also offers the Company the security of predictable rate recovery and the prospect of steady earnings, which will assist us in attracting capital to invest in electrical system improvements for our customers.

Dear Green Mountain Power shareholder:

It is a pleasure to report the accomplishments in 2003 of the men and women who devote large portions of their lives to Green Mountain Power. Their efforts have resulted in an outstanding year for our shareholders and customers. Together, we have achieved ambitious goals.

We enter 2004 in an enviable position.

FINANCIAL STRENGTH

The Vermont Public Service Board in December 2003 approved a long-term arrangement on electric rates designed to enhance our prospects of earning a 10.5 percent return on equity in each of the next three years. We are prepared for the unexpected surprises inherent in a volatile marketplace.

CUSTOMER FOCUS AND SATISFACTION

We enjoy the confidence of the vast majority of our customers.

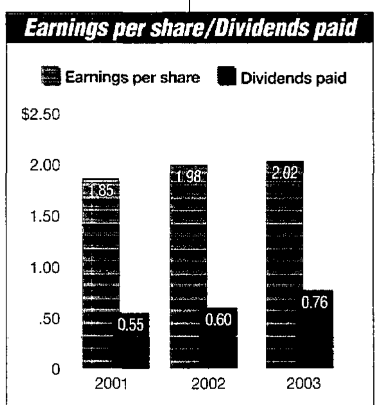
MOTIVATED PEOPLE

We have built a team that eagerly tackles new projects, is stimulated satisfying customers and embraces the constant change and opportunity we now see in our industry.

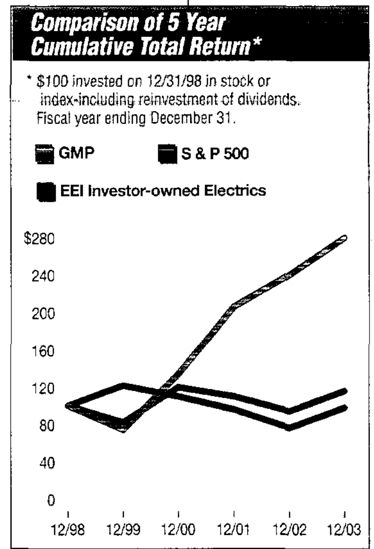
Higher Earnings

For the third straight year, Green Mountain Power hit its allowed return on common equity for core operations. Earnings per share for the year were $2.02, above the $1.98 we posted in 2002.

Green Mountain Power shareholders benefited from a steady upward movement in the price of Company stock from $20.97 per share at the end of 2002 to $23.60 per share at the end of 2003, an increase of 12.5 percent. When added to the $0.76 per share dividend that Green Mountain Power paid out during 2003, the total return for the year exceeded 16 percent. Over a five-year period, Green Mountain Power's total return of 180.9 percent ranked third in the nation among all utilities, according to the Edison Electric Institute index.



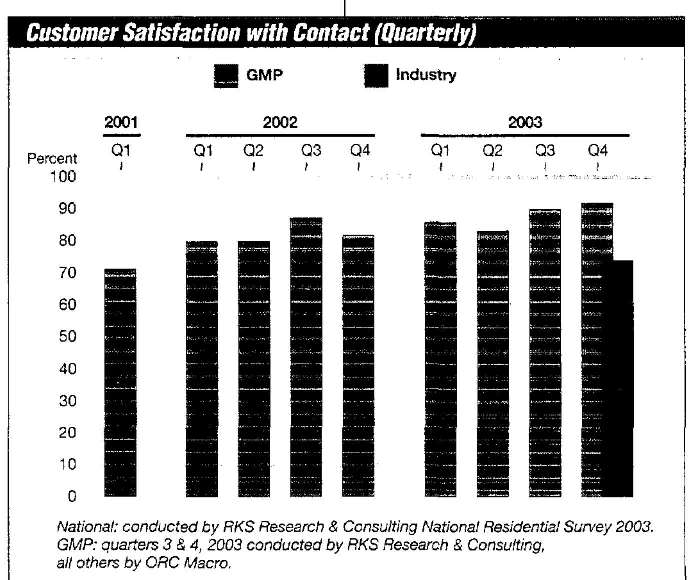
In February 2004, your Board of Directors approved a 16 percent increase in the dividend payment to an indicated annual rate of $0.88 per share. We intend to grow our dividend payout over the next five years, so long as our financial health seems assured. We anticipate that our dividend will grow at a double-digit average through this period. The increase in the dividend will benefit our customers by minimizing our cost of capital.

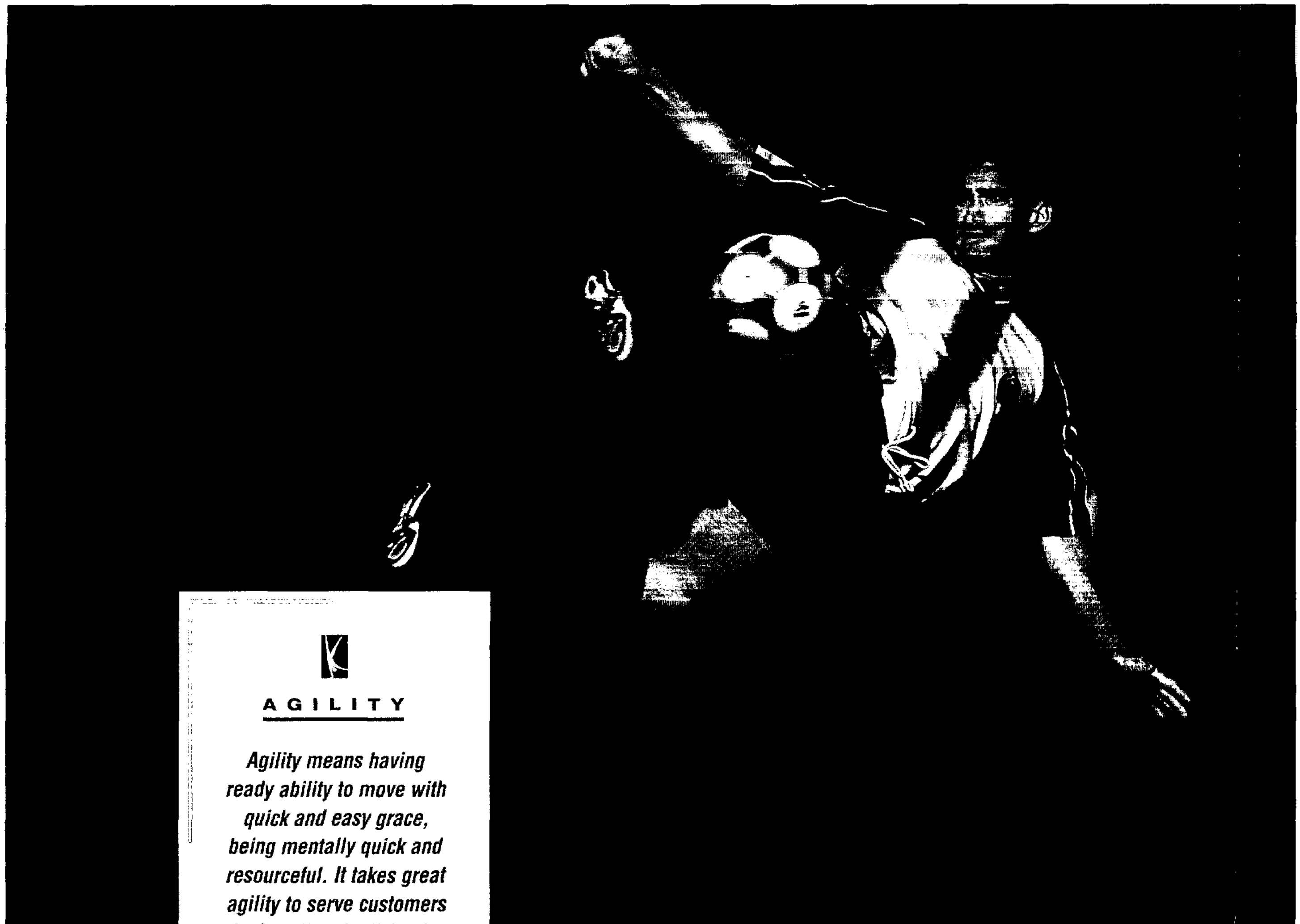


Delivering Superior Service

We believe the most important way to accomplish our goals for shareholders is to have a laser focus on delivering superior energy services to our customers. During 2003 we met or exceeded all of our Vermont Public Service Board approved service quality standards. We answered our phones within 20 seconds 82 percent of the time, we eliminated busy signals, bills were rendered on time and accurately, and official customer complaints to the regulators were only one for every 2,000 customers. Perhaps most importantly, we provided reliable power. On average, our customers experienced fewer than two outages last year, and those outages were about two hours each. We are proud to report that 94 percent of our customers expressed satisfaction with our reliability.

Customers notice good service, as evidenced by what they tell us in independent surveys. Every quarter we survey customers who have interacted with us. In the fourth quarter of 2003, 92 percent of our customers indicated that they were satisfied with our





AGILITY

Agility means having ready ability to move with quick and easy grace, being mentally quick and resourceful. It takes great agility to serve customers both well and efficiently. We have achieved the distinction of being one of the electric utility industry's most efficient companies. Green Mountain Power serves 460 customers per employee, compared to a national average of 337.

response to their contact, compared to a recent national survey reporting a 74 percent satisfaction level for the industry as a whole.

National Recognition

While customers recognized our good service, the national press began reporting on the remarkable recovery Green Mountain Power has achieved over the past few years. *Business Week* ranked us 25th among "The Small-Cap Top 50" in its national index of small-cap companies, while Forbes.com used Green Mountain Power as an example of "companies (that) have fared far better than the overall industry." Green Mountain Power president Chris Dutton was featured in interviews in "The Deal" and on other nationally-broadcast web interviews, as well as several New York City financial radio station programs. In February 2004, senior vice president and chief operating officer Mary Powell was featured as one of *Fast Company* magazine's "Fast 50," which highlights, according to its website, "passionate people around the world with big ideas and strong convictions who are determined to make a difference."

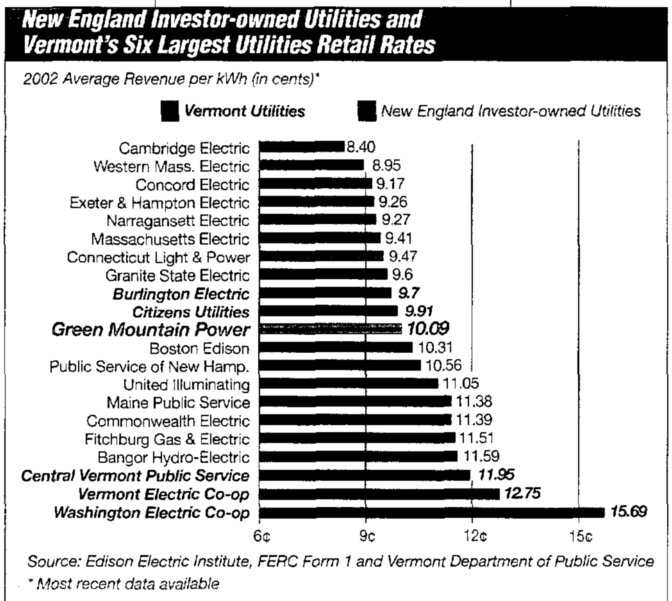
Stable Rate Plan

One of the most significant developments of the year was the three-year rate stability plan that we negotiated with the Vermont Department of Public Service, which received the Public Service Board's approval in December 2003.

GMP's Energy Sources 2003

Nuclear:		
Vermont Yankee		37.4 %
Hydro:		
Hydro-Québec	28.1	
GMP owned	4.5	
		32.6
Market Purchases:		19.2
Qualifying Facilities:		
Hydro	2.8	
Ryegate (wood)	2.5	
		5.3
Oil:		
Wyman	0.5	
GT&D	0.5	
MMWEC	1.7	
		2.7
Natural Gas:		
MMWEC		1.3
Wood:		
McNeil		1.0
Wind:		
Searsburg		0.5
TOTAL		100.00 %

This rate plan benefits both customers and shareholders, as it provides customers with a very stable rate path through 2006 and offers the Company the security of predictable rate recovery. We have agreed not to increase rates in 2004, to raise rates 1.9 percent in January 2005 and 0.9 percent in January 2006. Green Mountain Power last increased its rates in January 2001, so our customers will enjoy a six-year period during which rates are essentially flat. The rate settlement also provided that our return on equity be reduced from 11.25 percent to 10.50 percent, retroactive to January 2003. This steady earnings path, based on an attractive and fair, albeit lower, allowed return, will assist the Company in attracting capital to help finance electrical system investments to ensure customer reliability.



Source: Edison Electric Institute, FERC Form 1 and Vermont Department of Public Service

* Most recent data available

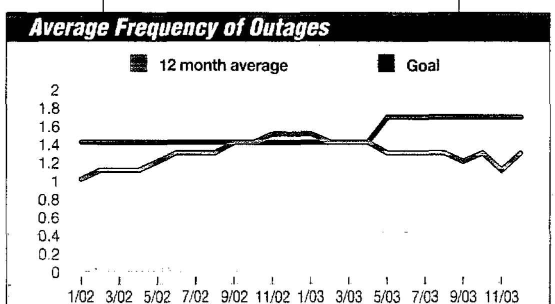
Central to our efforts to keep rates level has been our success in securing stable power supply sources. Two-thirds of our power comes from fundamentally fixed-price contracts with Hydro-Québec and the Vermont Yankee nuclear power plant. We have smaller contracts for power from several fossil fuel plants (but no coal-fired generation), and we have insulated ourselves through 2006 from substantial fluctuations in fossil fuel prices through our contract with Morgan Stanley. We retain our own hydro and peaking units, which have proven to be very valuable in periods of high demand.

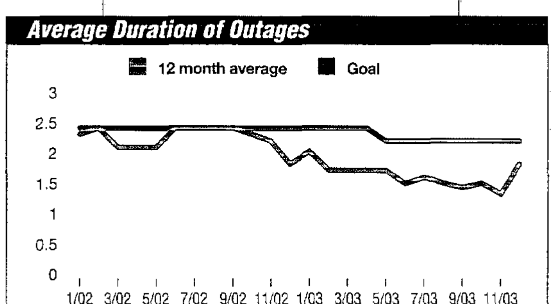
Power Supply Costs by Source

Source	2003 Cents per kWh
Average all sources	5.97
GMP hydro	3.05
Nuclear	4.31
Market purchases	6.14
Hydro-Québec	6.98
Wind	7.00
Oil and gas	8.47
Qualifying facilities	12.18

Reliability Investment

We escaped the massive blackout that much of the Midwest and Northeast experienced last August. Some Green Mountain Power customers experienced a brief "bump" in power, but only a few large industrial customers experienced any significant problems. Our system condition remained stable, although guarded, throughout the blackout.





The outage highlighted the need for Vermont to upgrade the transmission system serving the northwestern part of the state, which has been identified as the second most transmission-stressed in New England. The Vermont Electric Power Company (VELCO), Vermont's statewide transmission organization of which Green Mountain Power is a 30 percent owner, has proposed a major 75-mile upgrade from West Rutland to South Burlington, called the Northwest Reliability Project. This project is the most cost effective way to solve the reliability problem. If the project is approved and construction is completed by 2007, then costs will be shared by other customers throughout New England. Vermont's share of the $130 million in capital costs will be about $12 million.

VELCO intends to finance the cost of constructing the Northwest Reliability Project in part through increased equity investment. Green Mountain Power plans to invest approximately $20 million in VELCO to support this and other transmission projects through 2007. Transmission capacity is vital to continued economic growth and development in the state, as well as assuring the reliability of the system for current customers. Growth in transmission investment is consistent with our business model, which focuses on increased investment in regulated operations. Overall, we believe that, barring adverse circumstances, our earnings will grow by four to six percent for the next several years.

Poised for Growth

Last year we began marketing our utility services to other utilities across the state and in the Northeast region. We exceeded our goal of $2.5 million in additional sales through our business development activities, more than doubling 2002 sales.

Gov. James H. Douglas has made job creation "Job Number One" for his new administration, and he has supported our new stable rate agreement. Vermont is one of the few state governments in

the country operating with a balanced budget. State and private economists in Vermont are forecasting a strong year for 2004 with continued steady job and income growth. Your Company is well positioned to capitalize on the Vermont economy's vitality, as its service areas are located in the highest growth regions of Vermont.

The Douglas administration has begun a new initiative to make state government more effective. Recognizing the success Green Mountain Power achieved in this area, Governor Douglas asked David Coates, a member of Green Mountain Power's Board of Directors, to chair the Institute on Governmental Effectiveness. Mary Powell, Green Mountain Power's senior vice president and chief operating officer, who led our restructuring effort, was asked to serve as vice chair and secretary. We are pleased to be able to play

STRENGTH

A rider must be strong and in peak condition to compete successfully. Our financial strength depends ultimately on how well we serve our customers — and our customer service performance is strong. We have met or exceeded each of the 17 service quality standards established by the Vermont Public Service Board in areas such as answering the phone quickly, rendering bills on time and accurately, and delivering reliable electric service.

TEAMWORK

***No matter how hard the wind blows, the highly skilled and motivated team of Green Mountain Power employees works hard to harness resources to move quickly and efficiently. Our strong results have been making news across the country, from* Business Week *to Forbes.com to* Fast Company.**

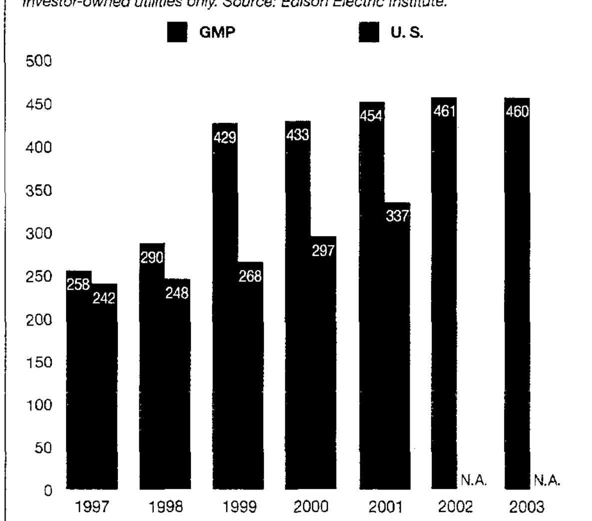
such a strong role in helping state government reach new levels of effectiveness.

Productivity Gains

We work hard at continuing the productivity improvements that played such an important role in our recent success. We remain among the most efficient electric utilities in the country, with 460 customers served per employee, compared to a nationwide utility average of 337 customers per employee in 2001.

Customers Served per Employee

Investor-owned utilities only. Source: Edison Electric Institute.



Maintaining this edge requires up-to-date information technology, and in 2003, we replaced our older financial programs with Oracle's new integrated financial system, which improves our operating efficiencies and internal controls.

Late in 2003 we signed a new four-year union contract. The contract provides for wage increases and benefit improvements for our employees, while achieving constraints on the Company's exposure to future health care cost inflation. The new contract also establishes safe guidelines for one-person work to improve operations and to respond better to customer needs.

Upon announcing the agreement, George Clain, president and assistant business manager of the IBEW Local 300, said, "We were able to solve issues much more effectively working in a cooperative process. The end result is an agreement that helps to protect the quality of life for retired and active employees at Green Mountain Power and provides for streamlining the operations of the Company."

Several years ago, as a way to reward employees and increase their interest in the success of the Company, we began awarding stock options to all employees. In 2003, we continued our compensation philosophy of sharing the success of the corporation by issuing common stock awards to every employee.

Green Mountain Power has

also embraced a new technology that benefits the environment with its purchase of hybrid vehicles. The vehicles combine a gas engine and electric motor to produce the optimum mix to power the car. Using hybrid vehicles reduces emissions and helps us evaluate the potential for expanded use of this technology in the future.

Corporate Governance

The national changes in corporate governance and financial reporting impose a heavy burden on small public companies, but in 2004 we enthusiastically reaffirmed our long-standing commitment to the principles of corporate integrity, ethical behavior and good corporate governance. As you would expect, your Company complies with the new governance standards for New York Stock Exchange listed companies. Our Board of Directors in 2003 adopted corporate governance guidelines, director independence standards as well as new and revised charters for our audit, governance and compensation committees. All of these are now posted on our website, along with our revised code of ethics. The Board also adopted new bylaws that returned to an annual election of all directors, rather than the staggered three-year terms under which directors had previously served.

We Pledge To Do Our Best

We celebrated the success outlined in this letter on February 13, 2004. We rang the closing bell at the New York Stock Exchange. A small delegation of employees accompanied president and chief executive officer Christopher L. Dutton, chief operating officer Mary G. Powell and senior vice president Stephen C. Terry to the NYSE to celebrate our excellent customer service and strong shareholder results. As Chris rang the bell, to the cheers of the stock exchange and our employees on the floor, and with the eyes of the world on us, Green Mountain Power stock traded at its highest point in seven years.

As satisfying as it is to report our strong results for 2003, we are realistic. The electric utility industry is still in a transition stage. That means we continue to confront associated market risks, including a volatile wholesale power market; and there are often just plain surprises because of unusual Vermont weather conditions, broader economic developments, such as fluctuations in interest rates, as well as things we just cannot foresee.

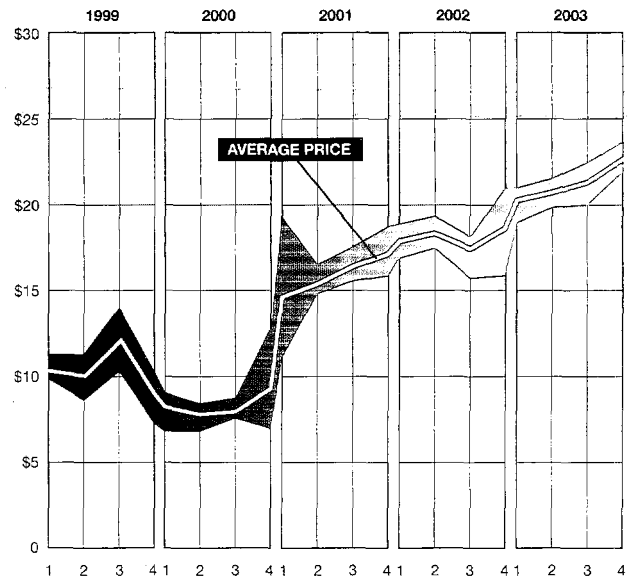
All we can pledge to you, our owners, is that we are prepared and very focused on our business plan. We will do our level best in 2004 to continue to give you confidence in your investment.

Nordahl L. Brue
Chairman

Christopher L. Dutton
President and
Chief Executive Officer

February 27, 2004

Quarterly Stock Market Price Data

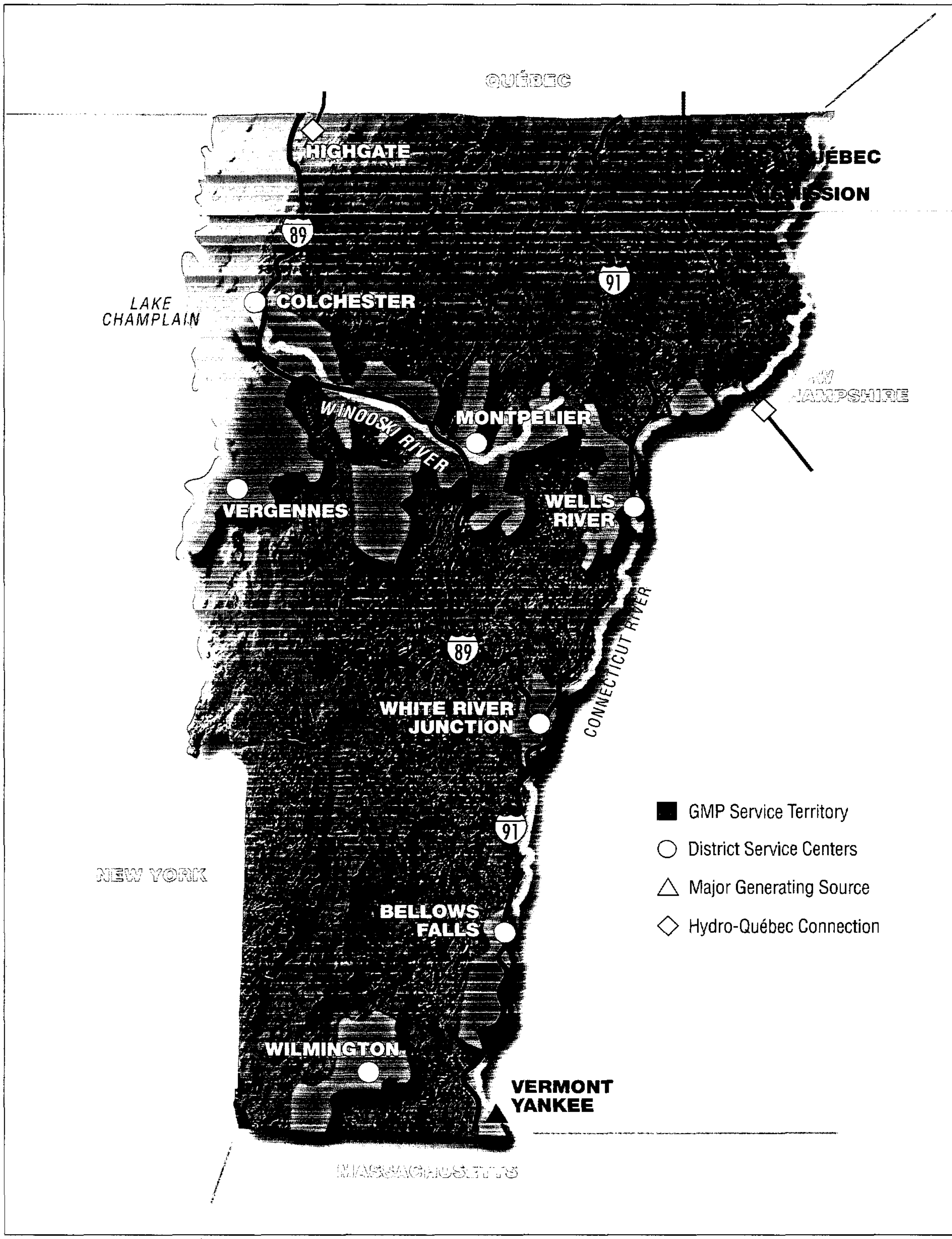


2003 ending stock price was $23.60.

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 1999 through 2003, as reported by the New York Stock Exchange. The number of registered shareholders of common stock as of December 31, 2003 was 5,172.

		Stock Price High	Stock Price Low	Dividend Declared
2003	First Quarter	$21.19	$19.02	19.00¢
	Second Quarter	21.78	20.00	19.00
	Third Quarter	22.72	20.06	19.00
	Fourth Quarter	23.84	21.98	19.00
2002	First Quarter	$19.00	$17.00	13.75¢
	Second Quarter	19.50	17.54	13.75
	Third Quarter	18.24	15.75	13.75
	Fourth Quarter	21.08	15.89	19.00

GMP Service Territories



Board of Directors

Nordahl L. Brue, 59, elected 1992, Chair, Green Mountain Power; Chairman, Franklin Foods Inc.; Chairman, PKC Corporation; Burlington, Vermont.

Elizabeth A. Bankowski, 56, elected 2002, business consultant in corporate social responsibility; Brattleboro, Vermont.

William H. Bruett, 60, elected 1986, Senior Vice President, The ESOP Advisory Group, UBS Financial Services, Inc.; Weehawken, New Jersey.

Merrill O. Burns, 57, elected 1988, President and CEO of The Simpata Group; San Francisco, California.

Lorraine E. Chickering, 53, elected 1994, former President of Public Communications of Bell Atlantic Corporation; Silver Springs, Maryland.

John V. Cleary, 75, elected 1980, retired President and Chief Executive Officer, GMP; Boynton Beach, Florida.

David R. Coates, 66, elected 1999, Executive Vice President, New England Culinary Institute; retired Partner, KPMG Peat Marwick; Burlington, Vermont.

Christopher L. Dutton, 55, elected 1997, President, Chief Executive Officer and Chairman of the Executive Committee of GMP; Colchester, Vermont.

Euclid A. Irving, 51, elected 1993, Partner, Paul, Hastings, Janofsky & Walker, LLP, Attorneys; New York, New York.

Board of Directors Committees

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

Compensation Committee
Merrill O. Burns, Chair
Elizabeth A. Bankowski
Lorraine E. Chickering
Euclid A. Irving

Executive Committee
Christopher L. Dutton, Chair
Nordahl L. Brue
William H. Bruett
David R. Coates

Governance Committee
William H. Bruett, Chair
Elizabeth A. Bankowski
Nordahl L. Brue
Lorraine E. Chickering
John V. Cleary

Strategic Issues Committee
Nordahl L. Brue, Chair
Lorraine E. Chickering
David R. Coates
Euclid A. Irving

Officers

Christopher L. Dutton
President and Chief Executive Officer

Robert J. Griffin
Vice President, Chief Financial Officer and Treasurer

Walter S. Oakes
Vice President, Field Operations

Mary G. Powell
Senior Vice President and Chief Operating Officer

Donald J. Rendall, Jr.
Vice President, General Counsel and Corporate Secretary

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

John V. Cleary and Lorraine E. Chickering retire from Board

We mark the end of an era with the retirement of John V. Cleary from the Board of Directors. Mr. Cleary has chosen not to run for re-election, ending 24 years of service on the Board. As President and Chief Executive Officer from 1983 until his retirement in 1993, he guided the Company through a difficult period, restoring regulatory confidence. We benefited significantly from his wisdom, leadership and friendship.

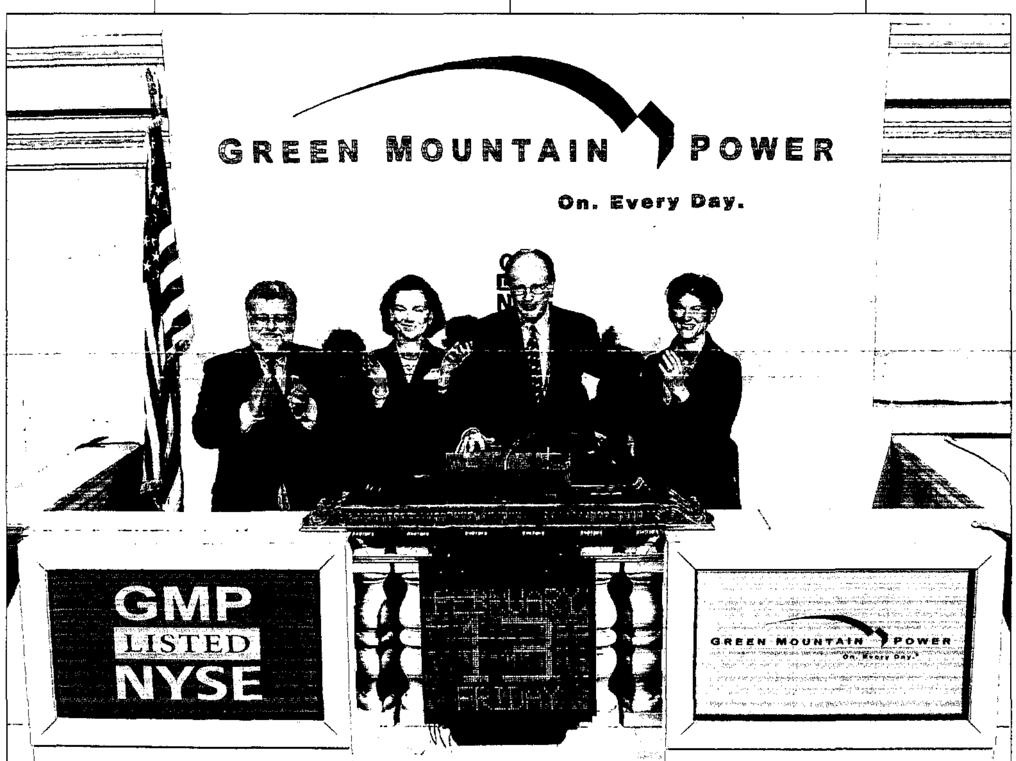
Lorraine E. Chickering, who completes ten years of service this year, has also decided not to run for re-election. Ms. Chickering brought us valuable insight from her distinguished career in telecommunications, another regulated industry in transition, and we are grateful for her years of service.

Kathleen C. Hoyt and Dr. Marc A. vanderHeyden nominated to Green Mountain Power Board

Kathleen C. Hoyt, 61 and Dr. Marc A. vanderHeyden, 65, have been nominated for election to Green Mountain Power's Board of Directors at the May 2004 Annual Meeting. Ms. Hoyt was the top cabinet official for Vermont Governor Howard Dean, having previously served in multiple leadership positions in state government. In 1998, she received the National Governors Association Award for Distinguished Service to State Government.

Dr. Marc A. vanderHeyden is the president of Saint Michael's College in Colchester, Vermont. Dr. vanderHeyden is a nationally recognized leader in higher education, directing Saint Michael's College's program to prepare students for life-long learning in a global society.

Green Mountain Power celebrated excellent customer service and strong shareholder results when president Chris Dutton rang the closing bell at the New York Stock Exchange February 13, 2004. He was joined on the platform by senior vice president of corporate and legal affairs Steve Terry, NYSE executive vice president Noreen Culhane, and senior vice president and chief operating officer Mary Powell, while a group of Green Mountain Power employees watched from the floor.



Executive Overview

Green Mountain Power Corporation (the "Company") generates virtually all of its earnings from retail electricity sales. Our retail electricity sales grow at an average annual rate of between one and two percent, about average for most electric utility companies in New England. While wholesale revenues are significant, they have relatively minor impact on our operating results and financial condition. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

The Company increased its dividend in February 2004 from an annual rate of $0.76 per share to $0.88 per share. The Company's dividend payout ratio remains comparatively low, at less than 45 percent of 2003 earnings. We expect to grow our dividend payout ratio to between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

Fair regulatory treatment is fundamental to maintaining the Company's financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders. In December 2003, the Company received approval from the VPSB of a new rate plan covering the period 2003 through 2006, which sets rates at levels the Company believes will provide an improved opportunity to recover our costs, and to earn our allowed rate of return.

Power supply expenses are equivalent to approximately 70 percent of total revenues. The Company's need to seek rate increases from its customers frequently moves in tandem with increases in our power supply costs. We have entered into long-term power supply contracts for most of our energy needs. All of our power supply contract costs are currently being recognized in the rates we charge our customers. The risks associated with our power supply resources, including outage, curtailment, and other delivery risks, the timing of contract expirations, the volatility of wholesale prices, and other factors impacting our power supply resources and how they relate to customer demand are discussed below under "Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors."

We also discuss other risks, including load risk related to our largest customer, International Business Machines Corporation ("IBM"), and contingencies that could have a significant impact on future operating results and our financial condition.

Growth opportunities beyond the Company's normal investment in its infrastructure are also discussed, and include a planned increase in our equity investment in Vermont Electric Power Company, Inc. ("VELCO") and a planned increase in sales of utility services.

In this section, we explain the general financial condition and the results of operations for 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 affect our overall financial condition.

Our critical accounting policies are discussed below under "Quantitative and Qualitative Disclosures About Market Risk, and Other Factors," under "Liquidity and Capital Resources – Pension," in Note A, "Significant Accounting Policies," and in Note H, "Pension and Retirement Plans." Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate; the manner in which we account for certain power supply arrangements that qualify as derivatives; the assumptions that we make regarding defined benefit plans; and revenue recognition, particularly as it relates to unbilled and deferred revenues. These accounting policies, among others, affect the Company's significant judgments and estimates used in the preparation of its consolidated financial statements.

There are statements in this section that contain projections or estimates that are considered to be "forward-looking" as defined by the Securities and Exchange Commission (the "SEC"). 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 include:

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

We address these items in more detail below.

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

Earnings Summary

	2003	2002	2001
Consolidated earnings per share of common stock	$2.02	$1.98	$1.85
Consolidated return on average common equity	10.76%	11.03%	11.02%

The Company reported consolidated earnings of $2.02 per share of common stock, diluted, in 2003 compared to consolidated earnings of $1.98 per share, diluted, in 2002. The improvement in earnings per share reflected reduced power supply expenses to serve retail sales, an increase in sales to residential customers and a reduction in the number of common stock shares outstanding. These favorable developments more than offset increased administrative and general costs, a reduction in the Company's allowed rate of return, increased interest expense in 2003, and a decrease in the recognition of deferred revenues, compared with 2002.

Our financial health improved during 2001 and 2002. As a result, we were able to reduce significantly our cost of capital in the fourth quarter of 2002 by issuing new long-term debt and using a portion of the proceeds to acquire approximately 812,000 shares of our common stock. Our 2003 earnings per share improved by approximately $0.09 per share as a result of the stock buyback.

In December 2003, the VPSB approved a rate plan for the period 2003 through 2006 (the "2003 Rate Plan"), jointly proposed by the Company and the Vermont Department of Public Service (the "Department" or the "DPS"). The 2003 Rate Plan provides the Company with a stable, predictable rate path through 2006, a plan for full recovery of the Company's principal regulatory assets, and an improved opportunity for the Company to earn its allowed rate of return through 2006. The 2003 Rate Plan calls for no retail rate increases in 2003 or 2004, then scheduled increases of 1.9 percent effective January 1, 2005, and 0.9 percent effective January 1,

2006. The 2003 Rate Plan sets the Company's allowed return on equity from core utility operations at 10.5 percent, effective with 2003, and provides for an earnings cap at that level through 2006. The 2003 Rate Plan is summarized in more detail below under "Rates."

The VPSB's January 2001 rate order (the "2001 Settlement Order") allowed the Company to defer revenues of approximately $8.5 million, generated by leveling winter/summer rates during 2001, to help offset costs and realize our allowed rate of return during the 2001-2003 period. We recognized approximately $1.1 million of these deferred revenues to achieve our allowed rate of return during 2003, compared with approximately $4.4 million recognized in 2002. The VPSB has permitted the Company to carry over unused deferred revenues totaling approximately $3.0 million to 2004 as part of the 2003 Rate Plan.

The improvement in earnings from continuing operations in 2002, compared with 2001, resulted primarily from lower capital costs and other operating expenses, including:

- $0.9 million reduction in interest expense, reflecting lower interest rates and average debt levels;
- $0.8 million reduction in preferred stock dividends, reflecting the Company's redemption of outstanding preferred stock; and
- Recognition of $4.4 million in revenue deferred from 2001 under the 2001 Settlement Order.

These favorable results were partially offset by increased maintenance expense, transmission expense and power supply expense to serve retail customers, compared to 2001.

Quantitative and Qualitative Disclosures About Market Risk, and Other Risk Factors

We consider our principal risks to include power supply risks, our regulatory environment (particularly as it relates to the Company's periodic need for rate relief), risks associated with our principal customer, IBM, pension and postretirement healthcare costs and weather. Discussion of these and other risks, as well as factors contributing to mitigation of these risks, follows.

Power Supply Risk—The Company's most significant power supply contracts are the Hydro-Québec Vermont Joint Owners ("VJO") Contract (the "VJO Contract") and the Vermont Yankee Nuclear Power Corporation ("VY" or "Vermont Yankee") contract (the "Vermont Yankee Contract") which are summarized in the following table.

	2003 MWH	2003 $/MWH	2002 MWH	2003 $/MWH	Contract Period Ends
VJO Contract	664,225	$69.81	724,708	$66.11	2015
Vermont Yankee	884,585	$43.08	771,782	$44.55	2012

All of the Company's power supply contract costs are currently being recovered through rates approved by the VPSB.

We expect approximately 90 percent of our estimated customer demand ("load") requirements through 2006 to be met by these contracts and by our generation and other power supply resources. These contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices. The Company's power supply contracts are described in more detail below under the heading "Power Contract Commitments."

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Implementation of New England's wholesale market for electricity has increased volatility of wholesale power prices. Periods frequently occur when weather, availability of power supply resources and other factors cause significant differences between customer demand and electricity supply. Because electricity cannot be stored, in these situations the Company must buy or sell the difference into a marketplace that has experienced volatile energy prices. Volatility and market price trends also make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief.

During 2002, we estimate that the Company paid an additional $1.0 million for replacement power as the result of an unscheduled outage at the Vermont Yankee nuclear power plant. While the Vermont Yankee plant has had an excellent operating record, future unscheduled outages could occur at times when replacement energy costs are above Vermont Yankee Contract costs.

We sometimes experience energy delivery deficiencies under the VJO Contract as a result of outages or other problems with the transmission interconnection facilities over which we schedule deliveries. When such deficiencies occur, we purchase replacement energy on the wholesale market, usually at prices that are higher than VJO Contract costs.

Under the VJO Contract, Hydro-Québec has the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the contract. Hydro-Québec exercised the first of these load reduction options, effective for the year 2003. The net cost of Hydro-Québec's exercise of this option increased power supply expense during 2003 by approximately $1.2 million. During 2003, Hydro-Québec exercised its second option to reduce the load factor for 2004, which we estimate will increase power supply expense by approximately $1.0 million. We expect Hydro-Québec to exercise its third option in 2004 for deliveries occurring principally during 2005, at an estimated cost of $1.0 million to $1.2 million, based on current wholesale market prices for 2005.

Hydro-Québec also retains the right under the VJO Contract to curtail annual energy deliveries by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Québec. Hydro-Québec has not exercised this right and has not communicated to the Company any present intention to do so.

Under the VJO Contract, the VJO, including the Company, have two options to adjust deliveries by a five percent load factor. These options cannot be used to offset Hydro-Québec's reductions through 2005, but may be used after 2005 to manage power supply costs.

The Company has established a risk management program designed to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Some of these transactions present the risk of potential losses from adverse changes in commodity prices. Our risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions. Our principal power supply contract counter-parties and generators, Hydro-Québec, Entergy Nuclear Vermont Yankee, LLC ("ENVY") and Morgan Stanley Capital Group, Inc. ("Morgan Stanley"), all currently have investment grade credit ratings.

The Company has a contract with Morgan Stanley (the "Morgan Stanley Contract") that is used to hedge our power supply costs against increases in fossil fuel prices. Morgan Stanley purchases the majority of the Company's power supply resources at index prices for fossil fuel resources and specified prices for contracted resources and then sells power to the Company at a fixed rate to serve pre-established load requirements. This contract, along with other power supply commitments, allows us to fix the cost of most of our power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract is described in more detail below under the heading "Power Contract Commitments." The Morgan Stanley Contract is a derivative under Statement of Financial

	Option Value Model	Risk Free Interest Rate	Price Volatility	Average Forward Price	Contract Expires
Morgan Stanley Contract	Deterministic	3.4%	32%–29%	$42	2006
9701 Arrangement	Black-Scholes	4.6%	48%–27%	$60	2015

Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management has estimated the fair value of the future net benefit of this arrangement at December 31, 2003, is approximately $4.0 million.

We currently have an arrangement that grants Hydro-Québec an option (the "9701 arrangement") to call power at prices that are expected to be below estimated future market rates. The 9701 arrangement is described in more detail below under the heading "Power Supply Expenses." This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this arrangement at December 31, 2003, is approximately $23.7 million. We sometimes use forward contracts to hedge forecasted calls by Hydro-Québec under the 9701 arrangement.

The table above presents assumptions used to estimate the fair value of the Morgan Stanley Contract and the 9701 arrangement. The forward prices for electricity used in this analysis are consistent with the Company's current long-term wholesale energy price forecast.

The table below presents the Company's market risk of the Morgan Stanley and Hydro-Québec derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to approximately $1.2 million. Actual results may differ materially from the table illustration. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred.

Commodity Price Risk	At December 31, 2003 Fair Value (Cost)	Market Risk
	(In thousands)	
Morgan Stanley Contract	$ 3,990	$ 2,160
9701 Arrangement	(23,724)	(3,342)
	($19,734)	($1,182)

Regulatory Risk — Management believes that fair regulatory treatment is crucial to maintaining its financial stability, including its ability to attract capital.

Vermont is the only state in the New England region that has not adopted some form of electric industry restructuring. The Company, like all other electric utilities in Vermont, accordingly operates as a vertically integrated electric utility, with the obligation to serve all customers in our service territory with electrical transmission, distribution and energy supplies sufficient to satisfy customer load requirements.

Vermont does not have a fuel or purchased-power adjustment clause that would allow increases in power supply costs to be recovered immediately in the rates we charge customers. Historically, however, the VPSB has allowed electric utilities to defer material unexpected increases in power supply costs to future periods to permit recovery in future rates. Vermont law also allows electric utilities to seek temporary rate increases if deemed necessary by the VPSB to provide adequate and efficient service or to preserve the viability of the utility.

Electric utility rates in Vermont are set based on the utility's cost of service. As a result, Vermont electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards No. 71 ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, allows regulated entities, including the Company, 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.

Regulatory assets represent incurred costs that have been deferred because the Company has concluded that they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs. The Company filed its last retail rate case during 1998. Since that time we have deferred a material amount of expenditures as regulatory assets. These regulatory assets have been judged as probable of recovery by management. As of December 31, 2003, the most significant regulatory assets not being recovered in current rates are the following:

Regulatory Assets	At December 31, 2003	2002
	(In thousands)	
Pine Street Barge Canal	$12,954	$13,019
Demand-Side Management	6,713	6,434
Unscheduled VY Outage Costs	2,178	2,002
Total	$21,845	$21,455

The 2003 Rate Plan, approved by the VPSB in December 2003, provides for amortization and recovery of all of the regulatory assets listed above, beginning January 1, 2005. The Pine Street Barge Canal regulatory asset will be amortized over a period of 20 years without a return on the remaining balance of the asset. The remaining assets will be amortized over a five-year period. Both the demand-side management and the unscheduled VY outage costs accrue a return defined by the Federal Energy Regulatory Commission ("FERC") based on the capital structure of the utility ("AFUDC rate"). The AFUDC rate for 2003 for the Company was approximately 8.5 percent.

The Company currently complies with the provisions of SFAS 71. If we had determined that the Company no longer met the criteria for following SFAS 71, at December 31, 2003, the accounting impact would have been an extraordinary non-cash charge to operations of $55.5 million. Factors that could give rise to the discontinuance of SFAS 71 include:

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

There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless, in our estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected.

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 wholesale market price of power. We have discussed various market price scenarios with interested parties for the purpose of identifying stranded costs. Based on preliminary market price assumptions, which are likely to change, we estimate the Company's stranded costs to be between $206 million and $252 million over the life of the Company's current contracts.

If Vermont adopted retail competition or some other form of electric industry restructuring or if the VPSB issued a regulatory order containing provisions that did not allow the Company to recover above-market power costs, the Company could be required 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.

Customer Concentration Risk—IBM, the Company's largest customer, operates a manufacturing facility in Essex Junction, Vermont. IBM's electricity requirements for its facility accounted for approximately 24.1, 25.7, and 26.6 percent of the Company's retail MWh sales in 2003, 2002, and 2001, respectively, and 16.6, 17.3, and 19.2 percent of the Company's retail operating revenues in 2003, 2002, and 2001, 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 22, 2003, the VPSB approved a new three-year agreement between the Company and IBM, ending December 31, 2006. The price of power under the agreement is above our marginal costs of providing incremental service to IBM. The VPSB approval provides that the agreement automatically terminates if IBM's full-time-equivalent employment level at its Vermont facility served by the agreement drops by more than 5 percent from the level on the date of VPSB approval.

IBM has reduced its Vermont workforce by approximately 2,500 since 2001, to a level of approximately 6,000 employees. Company revenue from sales of electricity to IBM declined $1.8 million in 2003 compared with 2002. Our operating results were not adversely impacted by the reduction in sales to IBM due to continued revenue growth in other customer classes and because the gross margin on sales to IBM is relatively low. If we experienced a material reduction in earnings as a result of significantly lower retail sales, we would seek a retail rate increase from the VPSB. The Company is permitted to seek such a rate increase request under our approved 2003 Rate Plan. We are not aware of any plans by IBM to further reduce production at its Vermont facility. We currently estimate, based on a number of projected variables, that a hypothetical shutdown of the IBM facility would require a retail rate increase for all our remaining customers in the range of five to eight percent.

Pension and Postretirement Health Care Risk—Other critical accounting policies involve the Company's defined benefit pension and postretirement health care benefit plans. The reported costs of these plans depend upon numerous factors relating to actual plan experience and assumptions of future experience.

Pension and postretirement health care costs are affected by actual employee demographics, Company contributions to the plans, earnings on plan assets, and, for our postretirement health care plan, health care cost trends. The Company contributed $1.0 million and $3.5 million to its pension plan during 2002 and 2003, respectively, and we expect to contribute between $2.0 and $3.0 million during 2004.

Our pension and postretirement health care benefit plan assets consist of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may increase or decrease costs in future periods. Changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded defined benefit plan costs.

On December 17, 2003, the Company's employees ratified a four-year labor agreement that provides annual wage increases of between 3.5 and 4 percent and improved 401(k) and pension benefits for employees. The new labor agreement caps future postretirement healthcare employee benefits provided by the Company for the majority of the present workforce. The cap on postretirement healthcare benefits is set approximately 13 percent above 2003 costs and grows at a 3 percent annual rate. This cap should reduce the rate at which postretirement healthcare expense grows in the future.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum liability of $2.4 million, net of applicable income taxes. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"). Favorable pension plan investment returns during 2003 reduced the OCI charge and related net liability by $587,000 million. The 2002 OCI charge and the 2003 OCI benefit had no effect on net income for either year.

Weather—The Company now uses weather insurance to mitigate some of the risk of lost electricity sales caused by unfavorable weather conditions. The Company has purchased weather insurance coverage for 2004. Coverage is based on cumulative variations from normal weather, measured in net heating and cooling degree-days.

Results of Operations

Operating Revenues and MWh Sales—Operating revenues, megawatthour ("MWh") sales and number of customers for the years ended 2003, 2002 and 2001 were as follows:

	Years ended December 31, 2003	2002	2001
	(Dollars in thousands)		
Operating Revenues:			
Retail*	$198,717	$201,052	$195,093
Sales for Resale	78,901	70,646	83,804
Other	2,852	2,910	4,567
Total Operating Revenues	$280,470	$274,608	$283,464
MWH Sales—Retail	1,934,340	1,948,190	1,953,154
MWH Sales for Resale	2,287,039	2,107,941	2,368,887
Total MWH Sales	4,221,379	4,056,131	4,322,041

*Retail revenues include $1.1 million, $4.4 million and $0.0 million of deferred revenue recognized for 2003, 2002 and 2001, respectively.

Average Number of Customers

	Years ended December 31, 2003	2002	2001
Residential	74,693	73,861	73,249
Commercial and Industrial	13,369	13,194	13,006
Other	65	65	65
Total Number of Customers	88,127	87,120	86,320

Comparative changes in operating revenues are summarized below:

Change in Operating Revenues	2002 to 2003	2001 to 2002
	(In thousands)	
Retail Rates	($ 912)	$ 6,471
Retail Sales Volume	(1,423)	(512)
Resales and Other Revenues	8,197	(14,815)
Increase (Decrease) in Operating Revenues	$ 5,862	($ 8,856)

In 2003, total electricity sales increased 4.1 percent compared with 2002, due to increased wholesale sales and sales to residential and commercial customers, partially offset by decreased sales to industrial customers. Total operating revenues increased $5.9 million, or 2.1 percent, compared with 2002 as a result of the following:

- Increased wholesale revenues of $8.3 million, primarily due to increased system sales during peak demand periods and increased sales to Hydro-Québec under the 9701 arrangement;
- Increased retail residential revenues of $3.2 million, or 4.5 percent, arising from increased sales of electricity; and
- Increased retail small commercial and industrial ("C&I") revenues of $900,000, or 1.3 percent, arising from increased sales of electricity.

These increases were partially offset for the following reasons:

- The Company recognized $1.1 million in deferred revenues under the 2001 Settlement Order, reduced from $4.4 million recognized in 2002.
- Decreased retail large C&I revenues of $2.6 million, or 1.7 percent, when compared with 2002, resulting from a decline in sales of electricity to this customer class.

In 2002, total electricity sales decreased 6.2 percent compared with 2001, due to reduced sales for resale under the 9701 arrangement with Hydro-Québec and our Morgan Stanley Contract, described in more detail below under the headings "Power Supply Expenses" and "Power Contract Commitments." Total operating revenues decreased $8.9 million, or 3.1 percent, in 2002 compared with 2001, due to decreases in sales for resale, partially offset by increased retail operating revenues. Retail operating revenues increased $6.0 million, or 3.1 percent, in 2002 compared with 2001 due to the recognition of $4.4 million of revenue deferred under the 2001 Settlement Order. Increased sales to residential and commercial customers also contributed to higher retail revenues, partially offset by a decline in revenues from IBM.

Power Supply Expenses — Power supply expenses constituted 74.4, 74.5 and 75.3 percent of total operating expenses for the years 2003, 2002, and 2001, respectively.

Power supply expenses increased by $3.9 million, or 2.0 percent, in 2003 when compared with 2002, and resulted from the following:

- an $8.3 million increase in the cost of power purchased for resale;
- a $2.7 million increase in power supply expenses under agreements with Hydro-Québec;
- higher costs of electricity supplied by independent power producers; and
- higher wholesale prices for electricity.

These increases were partially offset by an $8.9 million decrease in the cost of power under our contract with Morgan Stanley and lower unit prices from Vermont Yankee.

Power supply expenses decreased by $7.6 million, or 3.8 percent, in 2002 when compared with 2001, and resulted from the following:

- a $13.2 million decrease in power purchased for resale, primarily under the 9701 arrangement with Hydro-Québec and our Morgan Stanley Contract;
- a $3.5 million decrease in the net cost of the 9701 arrangement with Hydro-Québec; and
- a $2.1 million increase in the value of additional generation at the Company's hydroelectric plants, that allowed the Company to purchase less power during 2002.

These decreases were partially offset by:

- a $6.2 million increase in the cost of power purchased from Morgan Stanley;
- a $3.7 million net increase in the cost of power purchased from Vermont Yankee, including an offset of $1.4 million for the increase in value of additional generation purchased from the plant; and
- a $2.9 million increase in power purchased from independent power producers.

Power Contract Commitments — On February 11, 1999, the Company entered into a contract with Morgan Stanley (the "Morgan Stanley Contract") designed to manage price risks associated with changing fossil fuel prices. In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006.

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley 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. Morgan Stanley sells to the Company, at a predefined price, power sufficient to serve pre-established load requirements. Morgan Stanley is also responsible for scheduling supply resources. We remain responsible for resource performance and availability. Morgan Stanley provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company will reduce the power that it sells to Morgan Stanley. Some of our power-supply resources, including purchases pursuant to our Hydro-Québec and Vermont Yankee contracts, that were sold to Morgan Stanley through 2003, will no longer be included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley is expected to reduce wholesale revenues by approximately $64 million and correspondingly to reduce power supply expense by a similar amount. We do not expect this change to adversely affect the Company's opportunity to earn its allowed rate of return during 2004.

The Company's current purchases under the VJO Contract with Hydro-Québec 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, beginning in November 1995.

Our contracts with Hydro-Québec contain cross default provisions that allow Hydro-Québec to invoke "step-up" provisions under which the other Vermont utilities that are also parties to the contract would be required to purchase their proportionate share of the power supply entitlement of any defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro-Québec.

Under the Company's 9701 arrangement, 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 VJO Contract, which ends in 2015, Hydro-Québec may purchase up to 52,500 MWh on an annual basis ("option A") at the VJO Contract energy price, which is substantially below current market prices. The cumulative amount of energy that may be purchased under option A may not exceed 950,000 MWh (52,500 MWh in each contract year.)

Over the same period, Hydro-Québec may exercise an option to purchase up to 200,000 MWh on an annual basis at the VJO Contract energy price ("option B"). The cumulative amount of energy that may be purchased under option B may not exceed 600,000 MWh. As of December 31, 2003, Hydro-Québec had purchased 513,000 MWh under option B. The Company expects Hydro-Québec to call its remaining entitlements under option B during 2004 and 2005.

In 2003, Hydro-Québec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges.

In 2002, Hydro-Québec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges.

In 2001, Hydro-Québec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $6.5 million, including capacity charges.

We believe that it is probable that Hydro-Québec will call options A and B for 2004, and the Company has purchased replacement power at an incremental cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at an incremental cost of $1.1 million.

Vermont Yankee Nuclear Power Corporation

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to ENVY. As part of the sale transaction, Vermont Yankee entered into a Power Purchase Agreement ("PPA") with ENVY pursuant to which ENVY is obligated to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of our energy requirements. Prices under the PPA range from $39 to $45 per MWh for the period beginning January 2003, substantially lower than our forecasted cost if Vermont Yankee had continued to own and operate the plant facilities. In 2002, contract prices ranged from $49 to $55 under the PPA, higher than the forecasted cost of continued ownership. The PPA contains a provision known as the "low market adjuster," which calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning in November 2005. If market prices rise, however, PPA prices are not adjusted upward. The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the ENVY plant.

The Company received $8.2 million in October 2003, representing its share of the Vermont Yankee power plant sale proceeds, and used the proceeds to retire debt.

The Vermont Yankee sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervenor parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. The Court rejected the appeal and affirmed the VPSB approval during 2003.

Other Operating Expenses—Other operating expenses increased $3.5 million, or 24.5 percent, in 2003 compared with 2002 primarily due to increased employee benefit expenses and expenses related to corporate governance. A cap on post-retirement healthcare benefits, improved market returns and benefit plan funding should reduce growth in administrative and general expenses in 2004.

Other operating expenses decreased $1.7 million, or 10.9 percent, in 2002 compared with 2001. The decrease was primarily due to reduced consulting expenses of approximately $1.0 million and reduced distribution expenses of $0.6 million.

Transmission Expenses—Transmission expenses decreased $438,000, or 2.9 percent, in 2003 compared with 2002, due to decreased congestion costs allocated by ISO New England to Vermont utilities in conjunction with transition to a new standard market design ("SMD"). See discussion below.

Transmission expenses increased $1.1 million, or 7.7 percent, in 2002 compared with 2001. The Company's relative share of transmission expenses varies with the peak demand recorded on Vermont's transmission system. The Company's share of those expenses increased due to its increased load growth, relative to other Vermont utilities, and also because of increased transmission investment by VELCO.

The Independent System Operator of New England ("ISO-NE" or "ISO New England") was created to manage the operations of the New England Power Pool ("NEPOOL"), effective May 1, 1999. ISO-NE operates a market for all New England states for purchasers and sellers of electricity in the deregulated wholesale energy 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.

During 2002, the FERC accepted ISO-NE's request to implement a SMD governing wholesale energy sales in New England. ISO-NE implemented its SMD plan on March 1, 2003. SMD includes a system of locational marginal pricing of energy, under which prices are determined by zone, and based in part on transmission congestion experienced in each zone. Currently, the State of Vermont constitutes a single zone under the plan, although pricing may eventually be determined on a more localized ("nodal") basis. ISO-NE and NEPOOL have committed to facilitation of a stakeholder process to examine alternative pricing options, including alternatives to nodal pricing, and to file their report with FERC in July 2004. We believe that nodal pricing could result in a material adverse impact on our power supply and/or transmission costs, if adopted.

On October 31, 2003, ISO-NE, together with New England's principal transmission system owners including VELCO, filed a request for approval of a regional transmission organization for New England ("RTO-NE"). The proposed RTO-NE would become the provider of regional transmission service in New England, with operational control of the bulk power system and responsibility for administering markets currently operated and administered by ISO-NE. If the RTO is approved by FERC, the current ISO-NE agreement with the New England Power Pool ("NEPOOL"), the Restated NEPOOL Agreement, the NEPOOL Open Access Transmission Tariff and individual local tariffs currently maintained by New England transmission owners would terminate and be superseded by new RTO-NE agreements. Also on October 31, 2003, certain transmission owners in New England, including the Company, reached an agreement to submit a tariff, agreements and other documents to FERC to include costs associated with certain transmission facilities, known as the Highgate Facilities, of which the Company is a part owner, in region-wide rates as set forth in the RTO-NE proposal. The Company cannot predict whether or when FERC will approve the RTO-NE proposal, or what modifications may be made to the proposal while pending before FERC.

VELCO, the owner and operator of Vermont's principal electric transmission system assets, has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. We own approximately 29 percent of VELCO. The proposed Northwest Reliability Project must be approved by the VPSB. Several Vermont municipalities, citizen groups and individuals have intervened in the VPSB proceedings to oppose or request modifications to the project. If approved, the project is estimated to cost approximately $130 million through 2007. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment. The Company plans to invest approximately $20 million in VELCO to support this and other transmission projects through 2007. Under current NEPOOL and ISO-NE rules, which require qualifying large transmission project costs to be shared among all New England utilities, most of the costs of the Northwest Reliability Project will be allocated throughout the New England region, with Vermont utilities responsible for approximately five percent of allocated costs.

In August 2003, a coalition of New England public utility commissions and other parties challenged the NEPOOL and ISO-NE transmission cost allocation rules. On December 18, 2003, FERC rejected this challenge. FERC's order is subject to pending requests for rehearing and has been appealed to the US Court of Appeals for the D.C. Circuit. If the current transmission cost allocation rules are modified or eliminated, Vermont utilities, including the Company, could be required to bear a greater proportion, and potentially all, of the cost of the Northwest Reliability Project.

Maintenance Expenses—Maintenance expenses increased $211,000, or 2.4 percent, in 2003 compared with 2002, due to increased expenditures related to hydroelectric generation and transmission facilities.

Maintenance expenses increased $1.7 million, or 24.6 percent, in 2002 compared with 2001 due to increased expenditures related to storm damage and right-of-way maintenance programs.

Depreciation and Amortization—Depreciation and amortization expense decreased $348,000, or 2.5 percent, in 2003 compared with 2002 due to reductions in amortization of conservation and software programs, partially offset by increased depreciation of utility plant in service.

Depreciation and amortization expense decreased $143,000, or 1.0 percent, in 2002 compared with 2001 due to reductions in depreciation of utility plant in service partially offset by increased amortization of software costs.

Taxes Other than Income—Taxes other than income taxes decreased $201,000, or 2.6 percent, in 2003 compared with 2002 due to reductions in property taxes.

Taxes other than income taxes increased $87,000, or 1.2 percent, in 2002 compared with 2001 due to an increase in property taxes.

Income Taxes—Income tax expense decreased $923,000, or 15.2 percent, in 2003 compared with 2002 due to a decrease in the Company's taxable income, an increase in non-taxable income and the use of tax credits. Income tax expense decreased $905,000 in 2002 compared with 2001 due to a decrease in the Company's taxable income.

Other Income—Other income decreased $406,000, or 16.4 percent, in 2003 compared with 2002 due primarily to reduced earnings on investment in Vermont Yankee as a result of the sale of the Vermont Yankee plant in 2002.

Other income increased $112,000, or 4.7 percent, in 2002 compared with 2001 due primarily to Vermont Yankee recognition of deferred tax assets arising in conjunction with the sale of the Vermont Yankee plant, offset in part by payments made to Vermont Yankee owners located outside of Vermont necessary to close the sale of the Vermont Yankee plant.

Interest Expense—Interest expense increased $887,000, or 14.4 percent, in 2003 compared with 2002 primarily due to a $42 million long-term debt issuance in December 2002.

Interest expense decreased $869,000, or 12.3 percent, in 2002 compared with 2001 primarily due to scheduled and early redemptions of long-term debt and reduced short-term borrowing rates offset in part by higher average balances for short-term borrowings.

Dividends on Preferred Stock—Dividends on preferred stock decreased $93,000, or 96.9 percent, in 2003 compared with 2002, due to the repurchase of all outstanding preferred stock during 2003. Dividends on preferred stock decreased $837,000, or 90 percent, in 2002 compared with 2001 due to the repurchase of all outstanding preferred stock other than the 4.75 percent Class B shares.

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.

Pine Street Barge Canal Superfund Site—In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. In 2003, the Company expended $2.6 million to cover its obligations under the consent decree and we have estimated total future costs of the Company's future obligations under the consent decree to be $8.5 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $13.0 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of incurred costs over 20 years without a return. The amortization will be allowed in future rates, without disallowance or adjustment, until fully amortized.

Rates

Retail Rate Cases—On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed earlier in the year by the Company and the Vermont Department of Public Service. The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

- The Company's rates will remain unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase is required for the Company to meet its revenue requirements, the Company will implement the lesser rate increase.
- The Company may seek additional rate increases in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.
- The Company's allowed return on equity is reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. Any excess earnings in 2004 will be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.
- The Company will carry forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003, from the Company's 2001 Settlement Order (summarized below). These revenues will be applied in 2004 to offset increased costs or, if applicable, reduce regulatory assets as determined by the DPS.
- The Company will amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.
- The Company will file with the VPSB in early 2004 a new fully-allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval and is not expected to adversely affect operating results.
- The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan.

In January 2001, the VPSB issued the 2001 Settlement Order, which included the following:

- The Company received a rate increase of 3.42 percent above existing rates and prior temporary rate increases became permanent;

- Rates were set at levels that recover the Company's VJO Contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
- Seasonal rates were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001, which was deferred and available to be used to offset increased costs during 2002 and 2003; and
- The Company agreed to an earnings cap on core utility operations of 11.25 percent return on equity, with amounts earned over the limit being used to write off regulatory assets.

The 2001 Settlement Order also imposed two additional conditions:

- The Company and customers shall 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, adjusted for inflation; and
- The Company's further investment in non-utility operations is restricted until new rates go into effect, which will occur in January 2005.

Liquidity and Capital Resources

Construction and Investments—Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. The Company plans to invest up to $20 million in VELCO through 2007, subject to regulatory approval of the Northwest Reliability Project. See detailed discussion under "Transmission Expenses."

The Company offers utility services, primarily line construction and electrical services, principally to municipal and business customers. Sales of these services have grown from approximately $700,000 in 2001 to approximately $2.5 million in 2003. Sales of these services have allowed the Company to serve its customers more efficiently and have improved cash flow.

Future capital expenditures are expected to approximate $20 million annually. Expected reductions in Pine Street remediation costs should be offset by increased generation expenditures. Capital expenditures, net of customer advances for construction, over the past three years and forecasted for 2004 are as shown below.

Dividend Policy—The annual dividend was $0.60 per share for the year ended December 31, 2002. The annual dividend rate was increased by the Company's Board of Directors from $0.55 per share to $0.76 per share beginning with the $0.19 quarterly dividend declared in December 2002. On February 9, 2004, the annual dividend rate was increased from $0.76 per share to $0.88 per share, a payout ratio of approximately 44 percent based on 2003 earnings. The Company expects to increase the dividend in the first quarter of each year until the payout ratio falls between 50 percent and 70 percent of anticipated earnings. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles.

Financing and Capitalization

At December 31, 2003, our capitalization consisted of approximately 51 percent common equity and 49 percent debt, inclusive of the Company's capital lease obligations.

During June 2003, the Company negotiated a 364-day revolving credit agreement (the "Fleet-Sovereign Agreement") with Fleet Financial Services ("Fleet") joined by Sovereign Bank. The Fleet-Sovereign Agreement is for $20.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $500,000 outstanding with a weighted average rate of 4.0 percent on the Fleet-Sovereign Agreement at December 31, 2003. There was no non-utility short-term debt outstanding at December 31, 2003 or 2002. The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2004.

During 2002, we redeemed $5.1 million of 10.0 percent first mortgage bonds and $12.5 million of outstanding preferred stock. We also completed a "Dutch Auction" self-tender offer and repurchased 811,783 shares, or approximately 14 percent, of the Company's common stock outstanding for approximately $16.3 million in November 2002.

The Company negotiated a $12.0 million, two-year, unsecured loan agreement with Fleet, joined by KeyBank, on August 24, 2001. The $12.0 million loan was repaid on December 16, 2002.

The credit ratings of the Company's first mortgage bonds at December 31, 2003 were:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB+	Baa1	BBB

During August 2003, our rating agencies reviewed the Company's financial position and concluded the following:

- Moody's affirmed the Company's senior secured debt rating at Baa1, with a stable outlook;
- Fitch Ratings affirmed the ratings of the Company's first mortgage bonds at BBB+ with a stable outlook; and
- Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

In the event of a change in the Company's first mortgage bond credit rating to below investment grade, scheduled payments under the Company's first mortgage bonds would not be affected. Such a change would require the Company to post what would currently amount to a $4.3 million bond under our remediation agreement with the EPA regarding the Pine Street Barge Canal site. The Morgan Stanley Contract requires credit assurances if the Company's first mortgage bond credit ratings are lowered to below investment grade by any two of the three credit rating agencies listed above.

Capital Expenditures

	Generation	Transmission	Distribution (In thousands)	Other*	Total
Actual:					
2001	$2,323	$1,219	$8,567	$3,529	$15,638
2002	3,258	1,827	9,173	7,267	21,525
2003	2,629	1,496	7,760	7,064	18,949
Forecasted:					
2004	$4,122	$4,280	$6,036	$7,162	$21,600

*Other includes $1.5million in 2001, $1.8 million in 2002, $2.5 million in 2003, and an estimated $1.1 million in 2004 for the Pine Street Barge Canal site.

The following table presents a summary of certain material contractual obligations existing as of December 31, 2003.

	Payments Due by Period				
	Total	2004	2005 and 2006	2007 and 2008	After 2008
			(In thousands)		
Long-term debt	$ 93,000	$ —	$ 14,000	$ —	$ 79,000
Interest on long-term debt	76,055	6,534	13,068	11,068	45,385
Capital lease obligations	4,963	519	958	774	2,712
Hydro-Québec power supply contracts	623,463	49,419	101,239	101,847	370,958
Morgan Stanley Contract	38,664	13,602	25,062	—	—
Stony Brook Contract	46,081	3,509	5,754	6,328	30,490
Vermont Yankee PPA	288,410	35,808	67,672	67,767	117,163
Total	$1,170,636	$109,391	$227,753	$187,784	$645,708

Off-Balance Sheet Arrangements—The Company does not use off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments" and "Power Supply Expenses." We also own an equity interest in VELCO, which requires the Company to contribute capital when required and to pay a portion of VELCO's operating costs, including its debt service costs.

Other Risks—In March 2002, voters in the Town of Rockingham, Vermont ("Rockingham") approved an article authorizing Rockingham to create a municipal utility and to acquire the electric distribution systems of the Company and/or Central Vermont Public Service Corporation located within the town. In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers nor our shareholders effectively subsidize a Rockingham municipal utility.

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties in connection with this proceeding.

Governance—During 2003, the Securities and Exchange Commission ("SEC") issued a number of rules amending disclosure requirements for public company annual reports. In order to comply with such rules, the Company makes the following disclosures:

The Company's Board of Directors has determined that David Coates, who serves on the Company's Audit Committee, qualifies as an independent financial expert under SEC rules.

The Company has adopted a Code of Ethics and Conduct that applies to all Company directors and employees, including the Company's principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. The Company's code of ethics is maintained on its website at "www.greenmountainpower.biz," Who We Are, Investors, Corporate Governance. Upon request, the Company will provide a copy of its code of ethics to any person without charge. Please send your inquiries to attention of investor relations for the Company, 163 Acorn Lane, Colchester, Vermont 05446.

Management believes the Company to be in compliance with all governance and disclosure requirements of the New York Stock Exchange, the SEC, and applicable federal and state laws, including the "Sarbanes-Oxley" Act.

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 ("FASB") had agreed to review the accounting for closure and removal costs, including decommissioning. The FASB issued a new statement in August 2001 for "Accounting for Asset Retirement Obligations," which provides guidance on accounting for nuclear plant decommissioning costs, as well as other asset retirement costs. The Company does not believe that changes in such accounting, if required, would have an adverse effect on the results of our 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

	2003	2002	2001
		(In thousands, except per share data)	
Retail revenues	**$201,569**	$203,962	$199,660
Wholesale revenues	**78,901**	70,646	83,804
Operating Revenues	**$280,470**	$274,608	$283,464
Operating Expenses			
Power Supply			
Purchases from others	**189,450**	188,381	196,323
Company-owned generation	**7,856**	5,067	4,742
Other operating	**17,665**	14,188	15,924
Transmission	**14,783**	15,221	14,130
Maintenance	**9,065**	8,854	7,108
Depreciation and amortization	**13,803**	14,151	14,294
Taxes other than income	**7,422**	7,623	7,536
Income taxes	**5,120**	6,043	6,948
Total operating expenses	**265,164**	259,528	267,005
Operating income	**15,306**	15,080	16,459
Other Income			
Equity in earnings of affiliates and non-utility operations	**1,493**	2,777	2,253
Allowance for equity funds used during construction	**387**	233	210
Other income (deductions), net	**199**	(525)	(90)
Total other income	**2,079**	2,485	2,373
Interest Charges			
Long-term debt	**7,021**	5,214	6,073
Other	**303**	1,059	1,154
Allowance for borrowed funds used during construction	**(267)**	(103)	(188)
Total interest charges	**7,057**	6,170	7,039
Income before preferred dividends and discontinued operations	**10,328**	11,395	11,793
Dividends on preferred stock	**3**	96	933
Income from continuing operations	**10,325**	11,299	10,860
Income (Loss) from discontinued operations, net	**79**	99	(182)
Net Income (Loss) Applicable to Common Stock	**$ 10,404**	$ 11,398	$ 10,678
Earnings per Share			
Basic earnings per share from continuing operations	**$ 2.08**	$ 2.02	$ 1.93
Basic earnings (loss) per share from discontinued operations	**0.01**	0.02	(0.03)
Basic earnings per share	**$ 2.09**	$ 2.04	$ 1.90
Diluted earnings per share from continuing operations	**$ 2.01**	$ 1.96	$ 1.88
Diluted earnings (loss) per share from discontinued operations	**0.01**	0.02	(0.03)
Diluted earnings per share	**$ 2.02**	$ 1.98	$ 1.85
Weighted average shares outstanding–basic	**4,980**	5,592	5,630
Weighted average equivalent shares outstanding–diluted	**5,140**	5,756	5,789

Consolidated Statements of Comprehensive Income

	2003	2002	2001
Net Income	**$ 10,404**	$ 11,398	$ 10,678
Minimum pension liability adjustment, net of applicable income taxes of $400,000 expense and $1.6 million benefit, respectively	**587**	(2,374)	—
Other comprehensive income, net of tax	**$ 10,991**	$ 9,024	$ 10,678

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

	2003	2002	2001
		(In thousands)	
Operating Activities:			
Income from continuing operations before preferred dividends	**$ 10,328**	$ 11,395	$ 11,793
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**13,803**	14,151	14,294
Dividends from associated companies less equity income	**884**	45	(19)
Allowance for funds used during construction	**(654)**	(335)	(398)
Amortization of deferred purchased power costs	**318**	3,236	3,767
Deferred income taxes	**1,479**	3,577	345
Benefit plan contributions	**(3,500)**	(1,000)	—
Deferred purchased power costs	**(570)**	(2,003)	1,126
Accrued purchased power contract option call	**—**	—	(8,276)
Arbitration costs recovered (deferred)	**—**	—	3,229
Rate levelization liability	**(1,121)**	(4,483)	8,527
Environmental and conservation deferrals, net	**(1,890)**	(2,194)	(3,380)
Changes in:			
Accounts receivable and accrued utility revenues	**(189)**	(896)	6,483
Prepayments, fuel and other current assets	**(1,188)**	850	300
Accounts payable and other current liabilities	**(676)**	(55)	128
Accrued income taxes payable and receivable	**(3,950)**	5,010	1,187
Deferred tax liability	**5,776**	(1,147)	(2,512)
Other	**2,141**	2,458	(3,218)
Net cash provided by continuing operations	**20,991**	28,609	33,376
Net change in discontinued segment	**79**	99	(182)
Net cash provided by operating activities	**21,070**	28,708	33,194
Investing Activities:			
Construction expenditures	**(16,617)**	(19,543)	(12,963)
Investment in associated companies	**(108)**	(392)	—
Return in capital from associated companies	**7,615**	370	299
Investment in non-utility property	**(198)**	(206)	(212)
Net cash used in investing activities	**(9,308)**	(19,771)	(12,876)
Financing Activities:			
Proceeds from issuance of long-term debt	**—**	42,000	—
Payments to acquire treasury stock	**(3)**	(16,320)	—
(Reduction in) Proceeds from term loan	**—**	(12,000)	12,000
Repurchase of preferred stock	**(85)**	(12,536)	(235)
Issuance of common stock	**995**	1,037	1,655
Proceeds (Purchases) of certificate of deposit	**—**	—	16,173
Power supply option obligation	**—**	—	(16,012)
Reduction in long-term debt	**(8,000)**	(13,322)	(9,700)
Short-term debt, net	**(2,000)**	2,500	(15,500)
Cash dividends	**(3,792)**	(3,393)	(4,034)
Net cash used in financing activities	**(12,885)**	(12,034)	(15,653)
Net increase (decrease) in cash and cash equivalents	**(1,123)**	(3,097)	4,665
Cash and cash equivalents at beginning of period	**1,909**	5,006	341
Cash and Cash Equivalents at End of Period	**$ 786**	$ 1,909	$ 5,006
Supplemental Disclosure of Cash Flow Information:			
Cash paid year-to-date for:			
Interest (net of amounts capitalized)	**$ 7,120**	$ 6,048	$ 6,936
Income taxes	**2,915**	2,349	9,622
Supplemental Disclosure of Non-Cash Information:			
Minimum pension liability adjustment, net	**$ (587)**	$2,374	$ —

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

ASSETS	2003	2002
	(In thousands)	
Utility Plant		
Utility plant, at original cost	**$324,900**	$311,543
Less accumulated depreciation	**110,111**	102,250
Net utility plant	**214,789**	209,293
Property under capital lease	**5,047**	5,287
Construction work in progress	**9,026**	8,896
Total utility plant, net	**228,862**	223,476
Other Investments		
Associated companies, at equity	**5,896**	14,101
Other investments	**7,810**	7,451
Total other investments	**13,706**	21,552
Current Assets		
Cash and cash equivalents	**786**	1,909
Accounts receivable, less allowance for doubtful accounts of $690 and $547	**17,331**	17,253
Accrued utility revenues	**6,729**	6,618
Fuel, materials and supplies, at average cost	**4,498**	3,349
Prepayments	**1,922**	1,901
Other	**422**	402
Total current assets	**31,688**	31,432
Deferred Charges		
Demand side management programs	**6,713**	6,434
Purchased power costs	**2,574**	2,323
Pine Street Barge Canal	**12,954**	13,019
Net power supply deferral	**19,734**	18,405
Power supply derivative asset	**3,990**	8,796
Other deferred charges	**9,625**	11,413
Total deferred charges	**55,590**	60,390
Non-Utility		
Other current assets	**217**	8
Property and equipment	**248**	249
Other assets	**640**	738
Total non-utility assets	**1,105**	995
Total Assets	**$330,951**	$337,845

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

CAPITALIZATION AND LIABILITIES	2003	2002
	(In thousands, except share data)	
Capitalization		
Common stock, $3.33⅓ par value, authorized 10,000,000 shares (issued 5,860,854 and 5,782,496)	**$ 19,536**	$ 19,276
Additional paid-in capital	**76,081**	75,347
Retained earnings	**22,786**	16,171
Accumulated other comprehensive income	**(1,787)**	(2,374)
Treasury stock, at cost (827,639 and 827,639 shares)	**(16,701)**	(16,698)
Total common stock equity	**99,915**	91,722
Redeemable cumulative preferred stock	**—**	55
Long-term debt, less current maturities	**93,000**	93,000
Total capitalization	**192,915**	184,777
Capital Lease Obligation	**4,963**	5,287
Current Liabilities		
Current maturities of preferred stock	**—**	30
Current maturities of long-term debt	**—**	8,000
Short-term debt	**500**	2,500
Accounts payable, trade, and accrued liabilities	**8,493**	7,431
Accounts payable to associated companies	**6,821**	8,940
Rate levelization liability	**2,970**	4,091
Accrued income taxes	**633**	4,583
Customer deposits	**968**	898
Interest accrued	**1,152**	1,081
Other	**1,178**	937
Total current liabilities	**22,715**	38,491
Deferred Credits		
Power supply derivative liability	**23,724**	27,201
Accumulated deferred income taxes	**34,009**	26,471
Unamortized investment tax credits	**2,848**	3,130
Pine Street Barge Canal cleanup liability	**7,356**	8,833
Accumulated cost of removal	**21,238**	19,947
Other deferred liabilities	**19,693**	21,767
Total deferred credits	**108,868**	107,349
COMMITMENTS AND CONTINGENCIES		
Non-Utility		
Net liabilities of discontinued segment	**1,490**	1,941
Total non-utility liabilities	**1,490**	1,941
Total Capitalization and Liabilities	**$330,951**	$337,845

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

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Comprehensive Other Income	Treasury Stock	Total Common Equity
				(Dollars in thousands)			
BALANCE, December 31, 2000	**5,566,696**	**$18,608**	**$73,321**	**$ 493**	**$ —**	**($ 378)**	**$ 92,044**
Common Stock Issuance:							
DRIP and ESIP	105,767	352	1,218				1,570
Compensation Program	12,691	44	42				86
Net Income before Dividends				11,611			11,611
Common Stock Dividends				(3,101)			(3,101)
Preferred Stock Dividends				(933)			(933)
BALANCE, December 31, 2001	**5,685,154**	**19,004**	**74,581**	**8,070**	**—**	**(378)**	**101,277**
Common Stock Issuance:							
DRIP and ESIP	28,682	95	424				519
Common Stock Repurchase	(811,783)					(16,320)	(16,320)
Compensation Programs	52,804	177	342				519
Net Income before Dividends				11,494			11,494
Other Comprehensive Income (Loss)					(2,374)		(2,374)
Common Stock Dividends				(3,297)			(3,297)
Preferred Stock Dividends				(96)			(96)
BALANCE, December 31, 2002	**4,954,857**	**19,276**	**75,347**	**16,171**	**(2,374)**	**(16,698)**	**91,722**
Common Stock Issuance:							
Compensation Programs	78,358	260	734				994
Commmon Stock Repurchase						(3)	(3)
Net Income before Dividends				10,407			10,407
Other Comprehensive Income (Loss)					587		587
Common Stock Dividends				(3,789)			(3,789)
Preferred Stock Dividends				(3)			(3)
BALANCE, December 31, 2003	**5,033,215**	**$19,536**	**$76,081**	**$22,786**	**($1,787)**	**($16,701)**	**$ 99,915**

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

COMMON STOCK	Authorized	Shares Issued and Outstanding 2003	2002	2003	2002
				(In thousands)	
Common Stock,					
$3.33⅓ par value	10,000,000	**5,033,215**	4,954,857	**$19,536**	$19,276

	Authorized	Issued	Outstanding Shares 2003	2002	2003	2002
					(In thousands)	
Redeemable Cumulative Preferred Stock, $100 par value						
4.75%, Class B, redeemable at $101 per share	15,000	15,000	—	850	**$—**	$85
7%, Class C	15,000	15,000	—	—	**—**	—
9.375%, Class D, Series	40,000	40,000	—	—	**—**	—
7.32%, Class E, Series	200,000	120,000	—	—	**—**	—
Total Preferred Stock					**$—**	$85

LONG-TERM DEBT	2003	2002
	(In thousands)	
First Mortgage Bond		
6.41% Series due 2003	**$ —**	$ 8,000
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
6.04% Series due 2017—Cash sinking fund commences 2011	**42,000**	42,000
Total Long-term Debt Outstanding	**93,000**	$101,000
Less Current Maturities (due within one year)	**—**	8,000
Total Long-term Debt, Less Current Maturities	**$93,000**	$ 93,000

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 with a principal service territory that includes approximately one-quarter of Vermont's population. Nearly all of the Company's net income is generated from retail sales in its regulated electric utility operation, which purchases and generates electric power and distributes it to approximately 89,000 customer accounts. The Company's subsidiary, Green Mountain Power Investment Company ("GMPIC"), was created in December 2002 to hold the Company's investment in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VY").

The Company's remaining active wholly-owned subsidiary, which is not regulated by the Vermont Public Service Board ("VPSB" or the "Board"), is GMP Real Estate Corporation. The results of GMP Real Estate Corporation and the Company's unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income (Deductions) section of the Consolidated Statements of Income. Summarized financial information for these wholly-owned subsidiaries, and the Company's unregulated water heater program, which earned approximately $386,000 in 2003 is as follows:

	Years ended December 31,		
	2003	2002	2001
		(In thousands)	
Revenues	$1,087	$997	$1,012
Expenses	704	744	749
Net income	$ 383	$253	$ 263

The Company accounts for its investments in VY, 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 accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards No. ("SFAS") 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 increasing competition that restricts the Company's ability to recover specific costs, and 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 as summarized in the following table:

SFAS 71 Deferred Charges	At December 31,	
	2003	2002
	(In thousands)	
Regulatory Commission Costs	$ 2,181	$ 1,774
Restructuring Costs	943	2,216
Preliminary Survey	1,423	1,202
Storm Damages	1,129	1,905
Tree Trimming	799	905
Other	3,150	3,411
Other Deferred Charges	9,625	11,413
Power Supply	2,574	2,323
Net Power Supply Deferral	19,734	18,405
Pine Street Barge Canal	12,954	13,019
Power Supply Derivative Asset	3,990	8,796
Demand Side Management	6,713	6,434
Total Deferred Charges	$55,590	$60,390

Prior to the sale of the Vermont Yankee ("VY") nuclear generating plant (See Note B), the Company deferred and amortized certain replacement power, maintenance and other costs associated with outages at the VY generating plant. In addition, the Company accrued and amortized 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 its demand side management program and other regulatory assets, in a manner consistent with authorized or expected ratemaking treatment.

Other deferred charges totaled $9.6 million and $11.4 million at December 31, 2003 and 2002, respectively, consisting of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges, regulatory tax assets and various other projects and deferrals.

In addition, the Company has regulatory liabilities of $25.1 million and $24.0 million at December 31, 2003 and 2002, respectively, consisting of accumulated removal costs, deferred revenue and insurance proceeds relating to VY.

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 VPSB, the Vermont Department of Public Service ("DPS" or the "Department"), and the FERC, 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, 2003, based upon management's analysis of the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss should 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 a rate agreement with the DPS, the Company discontinued capitalizing 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 are charged to accumulated depreciation. The following table summarizes the Company's investments in utility plant.

Property Summary	At December 31, 2003	2002
	(In thousands)	
Property, Plant and Equipment:		
Intangible	$ 14,091	$ 12,580
Generation	68,532	66,913
Transmission	37,093	36,846
Distribution	178,292	170,655
General, including Transportation	26,892	24,549
Total Plant in Service	324,900	311,543
Accumulated Depreciation and Amortization	(110,111)	(102,250)
Net Plant in Service	214,789	209,293
Capital Lease	5,047	5,287
Construction Work in Progress	9,026	8,896
Total Net Utility Plant	$ 228,862	$ 223,476

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. Other accumulated removal costs related to utility plant, estimated at approximately $21.2 million and $19.9 million for 2003 and 2002, respectively, are included in Deferred Credits.

The annual depreciation provision was approximately 3.3 percent during 2003, 3.2 percent during 2002, and 3.5 percent of total depreciable property during 2001.

6. Cash and Cash Equivalents

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

7. Operating Revenues

Operating revenues consist principally of retail sales of electricity at regulated rates. Revenue is recognized when electricity is delivered. The Company accrues 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. Wholesale revenues represent sales of electricity to other utilities, typically for resale, and to the Independent System Operator of New England ("ISO New England") for amounts by which our power supply resources exceed customer loads. The Company also recognizes deferred revenues, when required to achieve its allowed rate of return, under a VPSB order issued in 2001, and extended through 2004 under a subsequent VPSB order. The Company recognized $1.1 million and $4.4 million in deferred revenues during 2003 and 2002, respectively. No deferred revenues were recognized in 2001. See Note I(4) for additional information.

8. Earnings Per Share

Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. During the year ended December 31, 2000, the Company established a stock incentive plan for all employees, and granted 335,300 options exercisable over vesting schedules of between one and four years. During 2003, 2002 and 2001, the Company granted additional options of 4,000, 80,300 and 56,450, respectively. See Note C for additional information. SFAS 123 requires disclosure of pro-forma information regarding net income and earnings per share. The Company adopted the prospective method of accounting for stock-based compensation under SFAS 148 beginning January 1, 2003. The following information has been determined as if the Company accounted for all past employee and director stock options under the fair value method of that statement.

Pro-forma net income	For the years ended December 31, 2003	2002	2001
	(In thousands, except per share amounts)		
Net income reported	$10,404	$11,398	$10,678
Pro-forma net income	$10,242	$11,114	$10,376
Net income per share			
As reported–basic	$2.09	$2.04	$1.90
Pro-forma basic	$2.06	$1.99	$1.84
As reported–diluted	$2.02	$1.98	$1.85
Pro-forma diluted	$1.99	$1.93	$1.79

9. Major Customers

The Company had one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 24.1 percent, 25.7 percent, and 26.6 percent of retail MWh sales, and 16.6 percent, 17.3 percent, and 19.2 percent of the Company's retail operating revenues in 2003, 2002 and 2001, respectively.

10. Fair Value of Financial Instruments

The carrying value and fair value of the Company's first mortgage bonds and derivative contracts are summarized in the following table:

	As of December 31 2003 Fair Value	2003 Carrying Value	2002 Fair Value	2002 Carrying Value
	(In thousands)			
Long-Term Debt, net	$91,725	$92,113	$96,215	$99,942
Derivatives	19,773	19,773	18,405	18,405

The book value of accounts receivable, accrued utility revenues, other investments, cash surrender value of life insurance, short-term debt, accounts payable, customer deposits and accrued interest approximate fair value due to their short-term, highly liquid nature.

11. Environmental Liabilities

The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. Only those site investigation, characterization and remediation costs currently known and determinable can be considered "probable and reasonably estimable" under SFAS 5, "Accounting for Contingencies". As costs become probable and reasonably estimable, reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures are expected to be recovered in rates. Estimates are based on studies provided by third parties.

12. Purchased Power

The Company records the annual cost of power obtained under long-term contracts as operating expenses.

13. Derivative Instruments

SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its 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. SFAS 133, as amended, was effective for the Company beginning 2001.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods caused by the application of SFAS 133 to power supply arrangements that qualify as derivatives. We currently have an arrangement ("9701") that grants Hydro-Québec an option to call power at prices below current and estimated future market rates. This arrangement is effective through 2015. From time to time, we use forward contracts to hedge the 9701 call option. At December 31, 2003, the Company had a liability of $23.7 million reflecting the fair value of the 9701 arrangement, and an asset of $4.0 million, reflecting the fair value of a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"). A corresponding net regulatory asset of $19.7 million is also recorded. At December 31, 2002, the Company had a liability of $27.2 million reflecting the fair value of the 9701 arrangement, and an asset of $8.8 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $18.4 million was also recorded. The Company believes that the net regulatory asset is probable of recovery in future rates. The net regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

The Morgan Stanley Contract is used to hedge against increases in fossil fuel prices. Morgan Stanley purchases the majority of the Company's 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.

14. Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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.

15. Reclassifications

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

16. Other Comprehensive Income

Other comprehensive loss of $2.4 million, net of a $1.6 million income tax benefit, was recognized during 2002 as a result of a minimum pension funding liability. During 2003, an increase in the market value of pension plan assets allowed a reduction in the minimum pension liability of approximately $587,000, net of $400,000 income tax expense.

17. New Accounting Standards

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), effective for fiscal years beginning after June 15, 2002, which provides guidance on accounting for nuclear plant decommissioning and other asset retirement costs. SFAS 143 prescribes fair value accounting for asset retirement liabilities, including nuclear decommissioning obligations, and requires recognition of such liabilities at the time incurred. The Company has recognized, as a liability, an asset retirement obligation for accumulated costs of removal, which totaled approximately $21.2 million and $19.9 million at December 31, 2003 and 2002, respectively, and increased plant and equipment balances by the same amount as a result of this accounting pronouncement.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"). SFAS 146 specifies accounting and reporting for costs associated with exit or disposal activities. The application of this accounting standard, which is effective for us during 2003, did not materially impact the Company's financial position or results of operations.

In December 2002, the FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-based Compensation-Transition and Disclosure" ("SFAS 148"). SFAS 148 amends Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting and reporting for stock-based employee compensation. The Company adopted the prospective method of accounting for stock-based compensation under SFAS 148 beginning January 1, 2003. The application of this accounting standard did not materially impact the Company's financial position or results of operation during 2003.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"("SFAS 150"). SFAS 150 establishes standards for classifying and measuring financial instruments with characteristics of both liabilities and equity. The guidance is effective for financial instruments entered into or modified after May 31, 2003. This statement had no effect on our financial position or results of operations during 2003.

In December 2003, the FASB issued Statement of Financial Accounting Standards No. 132 (revised 2003), "Employers" Disclosures about Pensions and Other Postretirement Benefits ("SFAS 132"). In an effort to provide the public with better and more complete information, the standard requires that companies provide more details about their plan assets, benefit obligations, cash flows, benefit costs and other relevant information. The guidance is effective for fiscal years ending December 15, 2003 and for quarters beginning after December 15, 2003. We have adopted all of the disclosures required by the standard.

In January 2003, the FASB issued FASB Interpretation No. ("FIN") 46, "Consolidation of Variable Interest Entities." FIN 46 requires a company to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interests. The adoption of FIN 46 did not require the Company to consolidate any variable interest entities.

In January 2003, the FASB issued FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The Company adopted the measurement provisions of this statement in the first quarter of 2003 and it did not have an effect on the financial statements during 2003.

The Company provides health care, life insurance, prescription drug and other benefits, to retired employees who meet certain age and years of service requirements. Under certain circumstances, eligible retirees are required to make contributions for postretirement benefits.

In December 2003, the FASB issued Staff Position ("FSP") 106-1, "Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the "Act"). The Act provides for drug benefits for certain retirees under a new Medicare Part D program. For employers like the Company there are subsidies available which are inherent in the Act. The FASB allowed, and the Company elected, a one-time deferral of the recognition of the impact of the Act in the employer's accounting until formal guidance is issued. As a result, the provisions of the Act are not reflected in the other postretirement benefits disclosure (See Note H). The issuance of formal accounting guidance may require a change to previously reported information.

B. Investments in Associated Companies

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

	Percent Ownership at December 31, 2003	Percent Ownership at December 31, 2002	Investment in Equity at December 31, 2003	Investment in Equity at December 31, 2002
			(In thousands)	
VELCO–Common	28.41%	28.41%	$2,469	$ 2,309
–Preferred	30.00%	30.00%	246	305
Total VELCO			2,715	2,614
Vermont Yankee–Common	33.60%	18.99%	1,605	9,721
New England Hydro-Transmission–Common	3.18%	3.18%	592	660
New England Hydro-Transmission Electric–Common	3.18%	3.18%	984	1,106
Total investment in associated companies			$5,896	$14,101

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 $12.0 million, $12.7 million, and $11.5 million for the years 2003, 2002 and 2001, respectively. Pursuant to VELCO's Amended Articles of Association, the Company is entitled to approximately 29 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. The Company plans to make capital investments of up to $20 million in VELCO through 2007 in support of various transmission projects.

Summarized unaudited financial information for VELCO is as follows:

	At and for the years ended December 31, 2003	2002	2001
		(In thousands)	
Net income	$ 1,270	$ 1,094	$ 1,118
Company's equity in net income	$ 418	$ 319	$ 308
Total assets	$128,793	$106,613	$89,322
Less:			
Liabilities and long-term debt	119,402	97,417	81,335
Net assets	$ 9,391	$ 9,196	$ 7,987
Company's equity in net assets	$ 2,715	$ 2,614	$ 2,352

Vermont Yankee

On July 31, 2002, Vermont Yankee Nuclear Power Corporation ("VY"or "Vermont Yankee") announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("ENVY") had been completed. See Note K for further information concerning our long-term power contract with VY.

During May 2002, prior to the sale of the plant to ENVY, the VY plant had fuel rods that required repair, a maintenance requirement that is not unique to VY. VY closed the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. The Company's share of the cost for the repair, including incremental replacement energy costs, was approximately $2.0 million. The Company received an accounting order from the VPSB on August 2, 2002, allowing it to defer the additional costs related to the outage, and believes that such amounts are probable of future recovery. The Company received a credit from VY and has requested permission from the VPSB to apply the credit to reduce the $2.0 million regulatory asset.

The Company's ownership share of VY has increased from approximately 19.0 percent in 2002 to approximately 33.6 percent currently, due to VY's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the ENVY nuclear plant remains at approximately 20 percent of plant production.

The 2003 decrease in equity in net assets of VY resulted from a distribution of proceeds, in the form of dividends to VY owners, from the sale of the VY nuclear power plant.

Summarized unaudited financial information for Vermont Yankee is as follows:

	At and for the years ended December 31, 2003	2002	2001
		(In thousands)	
Earnings:			
Operating revenues	$187,123	$175,722	$178,840
Net income applicable to common stock	$ 2,536	$ 9,454	$ 6,119
Company's equity in net income	$ 498	$ 1,745	$ 1,131
Total assets	$150,720	$201,426	$723,815
Less:			
Liabilities and long-term debt	145,946	150,413	669,640
Net assets	$ 4,774	$ 51,203	$ 54,175
Company's equity in net assets	$ 1,605	$ 9,721	$ 9,725

C. Common Stock Equity

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 416,328 shares were reserved and unissued at December 31, 2003. The Company also funds an Employee Savings and Investment Plan ("ESIP").

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

Prior to 2003, as permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation ("SFAS 123"), the Company had 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 issued through 2002. Under APB 25, because the exercise price equals the market price of the underlying stock on the date of grant, no compensation expense was recorded. Effective January 1, 2003, the Company elected to expense the fair value of options granted beyond that date. The amount of expense recorded during 2003 was immaterial. Options have been issued only to employees and directors.

The fair values of the options granted in 2003, 2002, and 2001 are $1.33, $2.27, and $4.16 per share, respectively. They were estimated at the grant date using the Black-Scholes option-pricing model. The following table presents information about the assumptions that were used for each plan year, and a summary of the options outstanding at December 31, 2003:

Plan Year	Weighted Average Exercise Price	Outstanding Options	Remaining Contractual Life	Risk Free Interest Rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
				Assumptions used in option pricing model			
2000	$ 7.90	192,200	6.6 years	6.05%	5	30.58	4.5%
2001	16.72	35,150	7.6 years	5.25%	6	32.69	4.0%
2002	17.84	69,500	8.6 years	4.50%	6.5	16.89	4.5%
2003	20.55	4,000	9.3 years	2.48%	6	13.68	4.5%
Total	$11.39	300,850					

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exer-cisable
Outstanding at 12/31/00	331,900	$ 7.90	$ 7.90–7.90	0
Granted	55,450	16.67	14.50–16.78	
Granted	1,000	12.28	12.28–12.28	
Exercised	17,400	7.90	7.90–7.90	
Forfeited	6,800	10.61	7.90–16.78	
Outstanding at 12/31/01	364,150	$ 9.20	$ 7.90–16.78	95,350
Granted	80,300	$17.82	$16.78–18.67	
Exercised	53,250	8.12	7.90–16.78	
Forfeited	25,400	9.35	7.90–18.67	
Outstanding at 12/31/02	365,800	$11.23	$ 7.90–17.82	151,775
Granted	4,000	$20.55	$20.22–22.62	
Exercised	64,550	10.63	7.90–18.67	
Forfeited	4,400	17.36	16.78–18.12	
Outstanding at 12/31/03	300,850	$11.39	$ 7.90–22.62	193,700

Options granted are not exercisable until one year after the date of grant.

The following table presents a reconciliation of net income to net income available to common shareholders, and the average common shares to average common equivalent shares outstanding:

Reconciliation of net income available for common shareholders and average shares

	For the years ended December 31, 2003	2002	2001
		(In thousands)	
Net income (loss) before preferred dividends	$10,407	$11,494	$11,611
Preferred stock dividend requirement	3	96	933
Net income (loss) applicable to common stock	$10,404	$11,398	$10,678
Average number of common shares–basic	4,980	5,592	5,630
Dilutive effect of stock options	160	164	159
Average number of common shares–diluted	5,140	5,756	5,789

As part of our long-term stock incentive program, 13,300 shares of unrestricted common stock were granted to employees other than the Company's executives during December 2003, resulting in compensation expense of approximately $300,000. Directors were granted 8,800 deferred stock units during 2003, resulting in compensation expense of approximately $196,000. The Company also granted 35,200 deferred stock units to senior management on February 9, 2004. Each deferred stock unit is convertible into one share of common stock. The total market value of the shares will be charged to compensation expense over a two-year vesting period.

On November 19, 2002, the Company completed a "Dutch Auction" self-tender offer and repurchased 811,783 common shares, or approximately 14 percent, of its common stock outstanding for approximately $16.3 million.

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 $19.9 million of retained earnings were free of restrictions at December 31, 2003.

D. Preferred Stock

During 2002, the Company repurchased all $12.0 million of the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company redeemed $0.3 million of the 7.0 percent Class C preferred stock outstanding. During November 2002, the Company repurchased the remaining $0.2 million of the 9.375 percent Class D preferred stock outstanding. All remaining preferred stock was repurchased during 2003.

E. Short-Term Debt

The Company has a $20.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by Sovereign Bank ("Sovereign"), expiring June 2004 (the "Fleet-Sovereign Agreement"). The Fleet-Sovereign Agreement is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was $500,000 outstanding at a weighted average rate of 4 percent under the Fleet-Sovereign Agreement at December 31, 2003. There was no non-utility short-term debt outstanding at December 31, 2003 or 2002.

The Fleet-Sovereign Agreement requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change". The agreement also requires the Company to comply with certain covenants. The Company was in compliance with all covenants at December 31, 2003.

F. Long-Term Debt

On December 16, 2002, the Company issued through private placement $42 million principal amount of first mortgage bonds bearing interest at 6.04 percent per year and maturing on December 1, 2017. The average duration of the bond issuance is twelve years and the bonds are subject to seven equal annual principal payments beginning on December 1, 2011. Proceeds were used to retire all of the Company's short and intermediate term debt, and to repurchase 811,783 shares of the Company's common stock.

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 7.0 percent for both December 31, 2003 and 2002. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) and long-term debt maturities for the next five years, as of December 31, 2003, are:

	Sinking Fund and Maturities
	(In thousands)
2004	$ —
2005	—
2006	14,000
2007	—
2008	—
Thereafter	79,000
Total long-term debt	$93,000

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, 2003 and 2002, the net regulatory assets were $924,000 and $1,042,000, 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, 2003 and December 31, 2002, were as follows:

	At December 31,	
	2003	2002
	(In thousands)	
Deferred Tax Assets		
Contributions in aid of construction	$11,841	$11,130
Deferred compensation and postretirement benefits	5,205	4,570
Self-insurance and other reserves	365	1,369
Other	1,277	3,032
	18,689	20,101
Deferred Tax Liabilities		
Property-related	43,924	41,967
Demand side management	1,746	1,870
Deferred purchased power costs	809	943
Pine Street reserve	2,425	1,792
Other	3,794	—
	52,698	46,572
Net accumulated deferred income tax liability	$34,009	$26,471

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 periods presented:

	Years ended December 31,		
	2003	2002	2001
	(In thousands)		
Net change in deferred income tax liability	$ 7,539	$ 2,712	($1,885)
Change in income tax related regulatory assets and liabilities	(6,175)	2,759	(1,149)
Change in tax effect of accumulated other comprehensive income	398	(1,612)	—
Deferred income tax expense (benefit)	$ 1,761	$ 3,859	($3,034)

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

	Years ended December 31,		
	2003	2002	2001
	(In thousands)		
Current federal income taxes	$2,434	$1,873	$ 7,846
Current state income taxes	1,207	593	2,418
Total current income taxes	3,641	2,466	10,264
Deferred federal income taxes	1,307	2,920	(2,296)
Deferred state income taxes	454	939	(738)
Total deferred income taxes	1,761	3,859	(3,034)
Investment tax credits—net	(282)	(282)	(282)
Income tax expense	$5,120	$6,043	$ 6,948

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,		
	2003	2002	2001
	(Dollars in thousands)		
Income before income taxes and preferred dividends	$15,527	$17,537	$18,559
Federal statutory rate	34.0%	34.0%	35.0%
Computed "expected" federal income taxes	5,279	5,963	6,496
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation	41	41	45
Dividends received and paid credit	(465)	(575)	(440)
AFUDC–equity funds	(129)	(80)	(72)
Amortization of ITC	(282)	(282)	(282)
State tax	797	1,011	1,705
Excess deferred taxes	(60)	(60)	(60)
Taxes attributable to subsidiaries	(25)	(31)	63
Other	(36)	56	(507)
Total federal and state income tax	$ 5,120	$ 6,043	$ 6,948
Effective combined federal and state income tax rate	33.0%	34.5%	37.4%

Non-Utility

The Company's non-utility subsidiaries, excluding Northern Water Resources, Inc. ("NWR"), had accumulated deferred income taxes of approximately $2,000 on their balance sheets at December 31, 2003, attributable to depreciation timing differences.

	At and for the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation as of prior year end	$29,937	$25,895	$ 20,707	$ 16,491
Service cost	755	668	496	296
Interest cost	1,900	1,849	1,316	1,119
Participant contributions	—	—	136	147
Plan change	—	—	(1,812)	—
Change in actuarial assumptions	292	—	2,095	—
Actuarial (gain) loss	2,789	3,230	(25)	3,619
Benefits paid	(1,629)	(1,650)	(1,007)	(965)
Administrative expense	(64)	(55)	—	—
Projected benefit obligation as of year end	$33,980	$29,937	$ 21,906	$ 20,707
Change in plan assets:				
Fair value of plan assets as of prior year end	$21,104	$24,341	$ 8,760	$ 10,016
Administrative expenses paid	(64)	(55)	—	—
Participant contributions	—	—	136	147
Employer contributions	3,500	1,000	782	819
Actual return on plan assets	4,956	(2,532)	1,558	(1,257)
Benefits paid	(1,629)	(1,650)	(1,007)	(965)
Fair value of plan assets as of year end	$27,867	$21,104	$ 10,229	$ 8,760
Funded status as of year end	($ 6,113)	($ 8,833)	($11,677)	($11,948)
Unrecognized transition obligation (asset)	—	(77)	2,952	3,280
Unrecognized prior service cost	984	839	(2,216)	(462)
Unrecognized net actuarial loss	6,372	6,982	9,250	8,379
Prepaid (Accrued) benefits at year end	$ 1,243	($ 1,089)	($ 1,691)	($ 751)

The components of the provision for the income tax expense (benefit) for the non-utility operations were not significant.

The effective combined federal and state income tax rate for the continuing non-utility operations was approximately 40 percent for each of the years ended December 31, 2003, 2002 and 2001. See Note L for income tax information on the discontinued operations of NWR.

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 No. 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 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 equity securities, fixed income securities, hedge funds and cash equivalent funds.

Due to sharp declines in the equity markets during 2001 and 2002, the value of assets held in trusts to satisfy the Company's pension plan obligations has decreased. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods.

The Company's funding policy is to make voluntary contributions to its defined benefit plans to meet or exceed the minimum funding requirements of ERISA or Pension Benefit Guaranty Corporation, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary pension plan contributions totaling $1.0 million during 2002 and made voluntary contributions totaling $3.5 million during 2003. The Company currently plans to contribute between $2.0 and $3.0 million of additional funds during 2004. The Company's pension costs and cash funding requirements could increase in future years in the absence of further recovery in the equity markets.

During 2002, the Company's retirement plan asset return experience required the Company to recognize a minimum pension liability of $4.0 million, and $1.6 million tax benefit, as prescribed by generally accepted accounting principles. Common equity was reduced in the amount of $2.4 million through a charge to other comprehensive income.

During 2003, market value appreciation of pension plan investments resulted in the reduction of the previously recognized minimum pension liability to $3.0 million. Common equity increased approximately $587,000, net of applicable income tax, through a credit to other comprehensive income.

Accrued postretirement health care expenses are recovered in rates. In order to maximize the tax-deductible contributions that are allowed under IRS regulations, the Company amended its postretirement health care 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, 2003 and 2002.

The Company also has a supplemental pension plan for certain employees. Pension costs for the years ended December 31, 2003, 2002, and 2001 were $392,000, $408,000, and $340,000, 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		
	2003	2002	2001	2003	2002	2001
	(In thousands)					
Service cost	$ 755	$ 668	$ 537	$ 496	$ 296	$ 241
Interest cost	1,900	1,849	1,737	1,316	1,119	1,043
Expected return on plan assets	(1,851)	(2,112)	(2,379)	(740)	(851)	(892)
Amortization of transition asset	(77)	(164)	(164)	—	—	—
Amortization of prior service cost	147	147	147	(58)	(58)	(58)
Amortization of the transition obligation	—	—	—	328	328	328
Recognized net actuarial gain	294	—	(237)	381	60	—
Net periodic benefit cost (income)	$ 1,168	$ 388	($ 359)	$1,723	$ 894	$ 662

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

Assumptions used in benefit obligation measurement

	For the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Weighted average assumptions as of year end:				
Discount rate	6.00%	6.50%	6.00%	7.00%
Expected return on plan assets	8.50%	9.00%	8.50%	8.50%
Rate of compensation increase	4.25%	4.25%	4.25%	4.25%
Medical inflation	—	—	9.25%	10.00%

Assumptions used in periodic cost measurement

	For the years ended December 31,			
	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Weighted average assumptions as of year end:				
Discount rate	6.50%	7.00%	6.50%	7.00%
Expected return on plan assets	8.50%	9.00%	8.50%	8.50%
Rate of compensation increase	4.25%	4.25%	4.25%	4.25%
Medical inflation	—	—	10.00%	7.50%

For measurement purposes, a 9.25 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2003. This rate of increase gradually declines to 5.5 percent in 2009. The medical 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, 2003 by $4.8 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2003 by $434,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2003 by $3.8 million, and the total of the service and interest cost components of net periodic postretirement cost for 2003 by $339,000.

Weighted Average Asset Allocation	Pension Assets For the years ended December 31,		
	Target 2004	2003	2002
	(Dollars in thousands)		
Asset category:			
Equity securities	65.00%	63.10%	59.61%
Debt securities	30.00%	24.92%	31.65%
Real estate	0.00%	0.00%	0.00%
Other	0.00%	6.60%	8.74%
Alternative investments	5.00%	5.38%	0.00%
Total	100.00%	100.00%	100.00%

The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the pension plan to meet its future obligations and to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 65 percent of plan assets be invested in equity securities, 30 percent of plan assets be invested in debt securities and the remainder be invested in alternative investments.

The Company expects an annual long-term return for the defined benefit plan asset portfolios of 8.25 percent, based on a representative allocation within the target asset allocation described above. In formulating the assumed rate of return, the Company considered historical returns by asset category and expectations for future returns by asset category based, in part, on expected capital market performance of the next ten years.

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 deregulation in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless in the Company's estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected. Alternative forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. 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. 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.

Pine Street Barge Canal Superfund Site

In 1999 the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal superfund site in Burlington, Vermont, known as the Pine Street Barge Canal. The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. In 2003, the Company expended $2.6 million to cover its obligations under the consent decree and we have estimated total future costs of the Company's net future obligations through 2033 under the consent decree to be $8.5 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have also recorded a regulatory asset of $13.0 million to reflect future recovery of these costs, as well as past unrecovered costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of these costs, as they are incurred, over 20 years without a return. The amortization will be allowed in future rates, without disallowance or adjustment, until fully amortized.

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. Jointly-Owned Facilities

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2003, as follows:

	Ownership Interest	Share of Capacity	Share of Utility Plant	Share of Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$10,296	$4,926
McNeil	11.0	5.9	8,989	5,379
Stony Brook (No. 1)	8.8	31.0	10,377	8,965
Wyman (No. 4)	1.1	6.8	1,980	1,380
Metallic Neutral Return	59.4	—	1,563	806

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.

4. Rate Matters

Retail Rate Cases

On December 22, 2003, the VPSB approved a three-year rate plan (the "2003 Rate Plan") jointly proposed earlier in the year by the Company and the Department. The 2003 Rate Plan, as approved, covers the period through 2006 and includes the following principal elements.

- The Company's rates will remain unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase in required for the Company to meet its revenue requirements, the Company will implement the lesser rate increase.
- The Company may seek additional rate increases in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.
- The Company's allowed return on equity is reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. If excess earnings result in 2004, they will be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.
- The Company will carry forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003 from the Company's 2001 rate case settlement summarized below. The Company will amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.
- The Company will file with the VPSB in early 2004 a new fully-allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval.
- The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003. The target for filing such a plan is April 2004. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan.

In January 2001, the VPSB approved a rate case settlement between the Company and the Department (the "2001 Settlement Order"). The final settlement, as approved, included the following:

- The Company received a rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases became permanent;
- Rates were set at levels that recover the Company's Hydro-Québec Vermont Joint Owners ("VJO") contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
- The Company agreed 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 agreed to write off in 2000 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 were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003;
- The Company agreed 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;
- The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the 1997 rate case; and
- The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets.

On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions:

- The Company and customers shall 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, adjusted for inflation; and
- The Company's further investment in non-utility operations is restricted.

The Company earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

The Company earned approximately $4.4 million less than its allowed rate of return during 2002 before recognition of deferred revenues in the same amount.

5. Deferred Charges Not Included in Rate Base

The Company has incurred and deferred approximately $11.1 million in costs for Pine Street, tree trimming, storm damage, and regulatory commission work, of which approximately $408,000 is being amortized on an annual basis. Currently, the Company amortizes such costs based on amounts being recovered and does not receive a return on amounts deferred. Management expects to recover these costs over periods ranging from five to twenty years beginning January 1, 2005, pursuant to the 2003 Rate Plan. The 2001 Settlement Order requires the remaining balance and future expenditures of deferred regulatory commission charges be amortized over seven years.

6. Competition

During 2001, the Town of Rockingham (Rockingham), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase the Bellows Falls hydroelectric facility from a third party, and the associated distribution plant owned by the Company within the town. In March 2002, voters in Rockingham approved an article authorizing Rockingham to create a municipal utility by acting to acquire a municipal plant, which would include the electric distribution systems of the Company and/or Central Vermont Public Service Corporation.

In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers nor our shareholders effectively subsidize a Rockingham municipal utility.

7. Other Legal Matters

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, complaining that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties in connection with this proceeding.

The Company is involved in other 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. At December 31, 2003, the present value of the Company's obligation is approximately $4.6 million.

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

	Years ending December 31, (In thousands)
2004	$ 387
2005	387
2006	387
2007	387
2008	387
Total for 2009–2015	2,712
Total	$4,647

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of National Grid USA. Certain of the Phase II participating utilities, including the Company, own equity interests in such companies. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities and accounts for its ownership under the equity method of accounting.

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 2003 follows:

	Stony Brook (Dollars in thousands)
Plant capacity	352.0 MW
Company's share of output	4.40%
Contract period expires:	2006
Company's annual share of:	
Interest	$ 128
Other debt service	444
Other capacity	535
Total annual capacity	$1,107
Company's share of long-term debt	$1,817

2. Vermont Yankee

The Company has a long-term power purchase contract with VY, which sold its nuclear power plant to ENVY on July 31, 2002. The Company is no longer required to pay its proportionate share of fixed costs associated with the ENVY plant, including when the plant is not operating, though the Company is responsible for finding replacement power at such times.

The VY sale of its nuclear power plant to ENVY also calls for ENVY, through its power contract with VY, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements.

A summary of the Purchase Power Agreement, including projected charges for the years indicated, follows:

	Vermont Yankee Contract (Dollars in thousands except per KWH)
Capacity acquired	106 MW
Contract period expires:	2012
Company's share of output	20%
Annual energy charge 2003	$37,288
Estimated 2004–2015	$32,377
Average cost per KWH 2003	$0.042
Estimated 2004–2015	$0.042

Payments totaling $0.5 million were made in 2002 to VY's non-Vermont sponsors in return for guarantees those sponsors made to ENVY to finalize the VY sale.

The Company received its share of the VY power plant sale proceeds, approximately $8.2 million, during October 2003, and used the proceeds to retire debt.

3. Hydro-Québec

Under various contracts, summarized 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 available. The Company's current purchases pursuant to the contract with Hydro-Québec entered into in December 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. There are specific step-up provisions that provide that in the event any 1987 Contract participant fails to meet its obligation under the 1987 Contract with Hydro-Québec, the remaining contract participants, including the Company, will step-up to the defaulting participant's share on a prorated basis.

Hydro-Québec also has the right to reduce the load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. The Company can delay such reduction by one year under the 1987 Contract. During 2001, Hydro-Québec exercised the first of these options for 2002, and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro-Québec's exercise of its option increased power supply expense during 2003 by approximately $1.2 million.

During 2003, Hydro-Québec exercised its second option to reduce the load factor for 2004, and we expect Hydro-Québec to exercise its third option in 2004 for deliveries occurring principally during 2005. Hydro-Québec also retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Québec. Under the 1987 Contract, Vermont joint owners, including the Company, have two remaining options to adjust deliveries by a five percent load factor. These cannot be used to offset Hydro-Québec's reductions through 2005, but may be used after 2005 to manage power supply costs.

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 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	46 MW
Contract Period	1995–2015	1995–2015
Minimum Energy Purchase (annual load factor)	65%–75%	65%–75%
Annual Energy Charge 2003	$10,565	$ 7,219
Estimated 2004–2015	$13,756 (1)	$ 9,400 (1)
Annual Capacity Charge 2003	$16,857	$11,519
Estimated 2004–2015	$17,122 (1)	$11,699 (1)
Average Cost per KWH 2003	$ 0.071	$ 0.071
Estimated 2004–2015	$ 0.064 (2)	$ 0.064 (2)

(1) Estimated average includes load factor reduction to 65 percent in 2004.
(2) Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro-Québec.

Under a separate arrangement established in December 1997 (the "9701 arrangement"), 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 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 the 9701 arrangement shall not exceed 950,000 MWh. Hydro-Québec's option to curtail energy deliveries pursuant to the 1987 Contract 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, 2003, Hydro-Québec had purchased or called to purchase 513,000 MWh under option B.

In 2003, Hydro-Québec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges.

In 2002, Hydro-Québec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges.

In 2001, Hydro-Québec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $6.5 million, including capacity charges.

The Company believes that it is probable that Hydro-Québec will call options A and B for 2004, and has purchased replacement power at an incremental cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at an incremental cost of $1.1 million.

4. Morgan Stanley Contract

In February 1999, the Company entered into a contract with MS. In August 2002, the MS contract was modified and extended to December 31, 2006. The contract provides the Company 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.

Beginning January 1, 2004, the Company will reduce the power that it sells to MS. The reduction in sales is expected to reduce wholesale revenues by approximately $64 million, and power supply expense by a similar amount. The Company does not expect the change to adversely affect its opportunity to earn its allowed rate of return during 2004.

The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. The MS contract is a derivative that includes a risk premium above expected future costs of electricity.

L. Discontinued Operations

The Company has sold or otherwise disposed of a significant portion of the operations and assets of NWR, which owned and invested in energy generation, energy efficiency, and wastewater treatment projects. The net reserve for loss from discontinued operations reflects management's current estimate. The residual operations earned $0.01 per share in 2003 and $0.02 per share in 2002, primarily as a result of adjustments to a reserve for warranty claims. At December 31, 2003, assets remaining include a wind power partnership investment, a note receivable from a regional hydro-power project, and notes receivable and equity investments with two wastewater treatment projects, one of which has risk factors that 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 against NWR. 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 discontinued operations during and at the periods shown:

	2003	2002	2001
	(In thousands except per share)		
Revenues	$ —	$ 88	$ 156
Gain (loss) on disposal	79	99	(182)
Net income (loss)	$ 79	$ 99	($ 182)
Net income (loss) per share–basic	$ 0.01	$ 0.02	($ 0.03)
Proceeds from asset sales	$ —	$ —	$ —
Total assets	$1,488	$1,622	$2,700
State income taxes	$ 12	$ 19	($ 175)
Federal income taxes	39	52	(550)
Investment tax credits	—	—	—
Income tax expense (benefit)	$ 51	$ 71	($ 725)

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.

	2003 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$72,945	$64,455	$71,975	$71,095	$280,470
Operating income	5,231	2,425	4,302	3,348	15,306
Net income–continuing operations	$ 4,084	$ 1,120	$ 3,034	$ 2,087	$ 10,325
Net income–discontinued operations	(13)	(8)	6	94	79
Net income applicable to common stock	$ 4,071	$ 1,112	$ 3,040	$ 2,181	$ 10,404
Basic earnings per share from:					
Continuing operations	$ 0.82	$ 0.22	$ 0.61	$ 0.43	$ 2.08
Discontinued operations	—	—	—	0.01	0.01
Basic earnings per share	$ 0.82	$ 0.22	$ 0.61	$ 0.44	$ 2.09
Weighted average common shares outstanding	4,959	4,969	4,982	5,009	4,980
Diluted earnings per share from:					
Continuing operations	$ 0.80	$ 0.22	$ 0.59	$ 0.40	$ 2.01
Discontinued operations	—	—	—	0.01	0.01
Diluted earnings per share	$ 0.80	$ 0.22	$ 0.59	$ 0.41	$ 2.02
Weighted average common and common equivalent shares outstanding	5,118	5,129	5,141	5,165	5,140

	2002 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$68,866	$65,135	$73,477	$67,130	$274,608
Operating income	4,441	2,814	3,745	4,080	15,080
Net income–continuing operations	$ 3,354	$ 1,875	$ 3,042	$ 3,028	$ 11,299
Net income–discontinued operations	—	—	—	99	99
Net income applicable to common stock	$ 3,354	$ 1,875	$ 3,042	$ 3,127	$ 11,398
Basic earnings per share from:					
Continuing operations	$ 0.59	$ 0.33	$ 0.53	$ 0.57	$ 2.02
Discontinued operations	—	—	—	0.02	0.02
Basic earnings per share	$ 0.59	$ 0.33	$ 0.53	$ 0.59	$ 2.04
Weighted average common shares outstanding	5,691	5,711	5,723	5,333	5,756
Diluted earnings per share from:					
Continuing operations	$ 0.57	$ 0.32	$ 0.52	$ 0.55	$ 1.96
Discontinued operations	—	—	—	0.02	0.02
Diluted earnings per share	$ 0.57	$ 0.32	$ 0.52	$ 0.57	$ 1.98
Weighted average common and common equivalent shares outstanding	5,870	5,877	5,879	5,497	5,756

	2001 Quarter Ended				
	March	June	Sept.	Dec.	Total
	(Amounts in thousands, except per share data)				
Operating revenues	$74,796	$67,471	$76,051	$65,146	$283,464
Operating income	4,575	4,275	4,573	3,036	16,459
Net income–continuing operations	$ 2,914	$ 2,884	$ 3,387	$ 1,675	$ 10,860
Net loss–discontinued operations	—	(150)	—	(32)	(182)
Net income applicable to common stock	$ 2,914	$ 2,734	$ 3,387	$ 1,643	$ 10,678
Basic earnings (loss) per share from:					
Continuing operations	$ 0.52	$ 0.52	$ 0.60	$ 0.29	$ 1.93
Discontinued operations	—	(0.03)	—	—	(0.03)
Basic earnings per share	$ 0.52	$ 0.49	$ 0.60	$ 0.29	$ 1.90
Weighted average common shares outstanding	5,588	5,615	5,644	5,672	5,630
Diluted earnings (loss) per share from:					
Continuing operations	$ 0.51	$ 0.50	$ 0.58	$ 0.29	$ 1.88
Discontinued operations	—	(0.03)	—	—	(0.03)
Diluted earnings (loss) per share	$ 0.51	$ 0.47	$ 0.58	$ 0.29	$ 1.85
Weighted average common and common equivalent shares outstanding	5,741	5,777	5,814	5,848	5,816

To the Board of Directors of
Green Mountain Power Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Green Mountain Power Corporation and subsidiaries (the Company) as of December 31, 2003, and 2002, and the related consolidated statements of income, comprehensive income, changes in stockholders equity and cash flows for each of the two years in the period ended December 31, 2003. The financial statements of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion which included an emphasis of matter paragraph on those financial statements in their report dated March 12, 2002. 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 of America. 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 financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2003 and 2002 and the results of their operations and their cash flows for each of the two years then ended in conformity with accounting principles generally accepted in the United States.

Deloitte & Touche LLP

Deloitte & Touche, LLP

Boston, Massachusetts
February 25, 2004

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, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001.

These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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, 2001 and 2000, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note A to the financial statements, effective January 1, 2001, the company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Arthur Andersen LLP

Boston, Massachusetts
March 12, 2002

The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP.

In thousands, except per share amounts	2003	2002	2001
Operating Revenues			
Residential	**$ 75,404**	$ 73,541	$ 69,727
Lease	**—**	—	—
Total residential and lease	**75,404**	73,541	69,727
Commercial and industrial–small	**74,070**	74,613	71,589
Commercial and industrial–large	**47,937**	50,932	53,777
Sales for resale	**78,901**	72,312	83,805
Other	**4,157**	3,210	4,566
Total operating revenues	**280,470**	274,608	283,464
Operating Expenses			
Power Supply			
Vermont Yankee Nuclear Power Corporation	**38,090**	35,252	30,114
Company-owned generation	**7,856**	5,067	4,742
Purchases from others	**151,360**	153,129	166,209
Other operating	**17,665**	14,188	15,924
Transmission	**14,783**	15,221	14,130
Maintenance	**9,065**	8,854	7,108
Depreciation and amortization	**13,803**	14,151	14,294
Taxes other than income	**7,422**	7,623	7,536
Income taxes	**5,120**	6,043	6,948
Total operating expenses	**265,164**	259,528	267,005
Operating income	**15,306**	15,080	16,459
Other Income			
Equity in earnings of affiliates and non-utility operations	**1,493**	2,777	2,253
Allowance for equity funds used during construction	**387**	233	210
Other income and deductions, net	**199**	(525)	(90)
Total other income	**2,079**	2,485	2,373
Income before interest charges	**17,385**	17,565	18,832
Interest Charges			
Long-term debt	**7,021**	5,214	6,073
Other	**303**	1,059	1,154
Allowance for borrowed funds used during construction	**(267)**	(103)	(188)
Total interest charges	**7,057**	6,170	7,039
Income (loss) before preferred dividends and discontinued operations	**10,328**	11,395	11,793
Dividends on preferred stock	**3**	96	933
Income (loss) from continuing operations	**10,325**	11,299	10,860
Net income (loss) from discontinued segment operations	**—**	—	—
Income (Loss) on disposal, including provisions for operating losses during phaseout period	**79**	99	(182)
Net Income (Loss) Applicable to Common Stock	**$ 10,404**	$ 11,398	$ 10,678
Common Stock Data			
Basic earnings (loss) per share from discontinued operations	**$ 0.01**	$ 0.02	($ 0.03)
Basic earnings (loss) per share from continuing operations	**2.08**	2.02	1.93
Basic earnings (loss) per share	**$ 2.09**	$ 2.04	$ 1.90
Diluted earnings per share from discontinued operations	**$ 0.01**	$ 0.02	($ 0.03)
Diluted earnings per share from continuing operations	**2.01**	1.96	1.88
Diluted earnings per share	**$ 2.02**	$ 1.98	$ 1.85
Cash dividends declared per share	**$ 0.76**	$ 0.60	$ 0.55
Weighted average shares outstanding–basic	**4,980**	5,592	5,630
Weighted average shares outstanding–diluted	**5,140**	5,756	5,789

	2000	1999	1998	1997	1996	1995	1994	1993
	$ 69,832	$ 67,061	$ 61,697	$ 61,423	$ 60,598	$ 55,434	$ 50,966	$ 49,391
	—	—	—	—	—	—	—	419
	69,832	67,061	61,697	61,423	60,598	55,434	50,966	49,810
	70,382	68,004	61,816	58,700	56,530	51,245	48,374	47,310
	45,729	43,518	40,201	37,841	36,704	32,616	31,381	31,569
	88,333	68,305	16,529	17,847	20,667	17,541	13,521	14,441
	3,050	4,160	4,061	3,512	4,510	4,708	3,955	4,123
	277,326	251,048	184,304	179,323	179,009	161,544	148,197	147,253
	34,813	34,987	32,910	32,817	30,596	30,222	30,300	29,785
	7,777	5,582	6,412	5,327	3,330	3,786	3,113	3,150
	168,947	142,699	81,706	62,222	66,320	53,915	45,777	46,066
	17,644	17,582	21,291	16,780	17,615	18,120	17,296	17,353
	14,237	10,800	9,389	11,122	10,833	9,874	10,374	10,775
	6,633	6,728	5,190	4,785	4,463	4,210	4,465	4,352
	15,304	16,187	16,059	16,359	16,280	14,116	10,683	8,572
	7,402	7,295	7,242	7,205	6,982	6,428	6,277	6,125
	(691)	1,242	(1,367)	7,191	6,463	5,578	5,395	6,249
	272,066	243,102	178,832	163,808	162,882	146,249	133,680	132,427
	5,260	7,946	5,472	15,515	16,127	15,295	14,517	14,826
	2,495	2,919	2,058	285	1,564	2,131	2,287	2,239
	284	134	104	357	175	27	263	273
	(73)	400	(549)	789	175	94	306	19
	2,706	3,453	1,613	1,431	1,914	2,252	2,856	2,531
	7,966	11,399	7,085	16,946	18,041	17,547	17,373	17,357
	6,499	6,716	6,991	7,274	6,872	6,546	6,868	6,539
	986	558	1,016	691	994	1,427	867	646
	(228)	(91)	(131)	(315)	(468)	(547)	(539)	(357)
	7,257	7,183	7,876	7,650	7,398	7,426	7,196	6,828
	709	4,216	(791)	9,296	10,643	10,121	10,177	10,529
	1,014	1,155	1,296	1,433	1,010	771	794	811
	(305)	3,061	(2,087)	7,863	9,633	9,350	9,383	9,718
	—	(603)	(2,086)	142	1,316	1,382	825	102
	(6,549)	(6,676)	—	—	—	—	—	—
	($ 6,854)	($ 4,218)	($ 4,173)	$ 8,005	$ 10,949	$ 10,732	$ 10,208	$ 9,820
	($ 1.19)	($ 1.36)	($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02
	(0.06)	0.57	(0.40)	1.54	1.95	1.97	2.05	2.18
	($ 1.25)	($ 0.79)	($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20
	($ 1.19)	($ 1.36)	($ 0.40)	$ 0.03	$ 0.27	$ 0.29	$ 0.18	$ 0.02
	(0.06)	0.57	(0.40)	1.54	1.95	1.97	2.05	2.18
	($ 1.25)	($ 0.79)	($ 0.80)	$ 1.57	$ 2.22	$ 2.26	$ 2.23	$ 2.20
	$ 0.55	$ 0.55	$ 0.96	$ 1.61	$ 2.12	$ 2.12	$ 2.12	$ 2.11
	5,491	5,361	5,243	5,112	4,933	4,747	4,588	4,457
	5,491	5,361	5,243	5,112	4,933	4,747	4,588	4,457

Consolidated Balance Sheets GREEN MOUNTAIN POWER CORPORATION • At December 31

Dollars in thousands

	2003	2002	2001
Assets			
Utility plant, at original cost	**$324,901**	$311,543	$302,489
Less accumulated depreciation	**110,112**	102,250	119,054
Net utility plant	**214,789**	209,293	183,435
Property under capital lease	**5,047**	5,287	5,959
Construction work in progress	**9,026**	8,896	7,464
Total utility plant, net	**228,862**	223,476	196,858
Associated companies, at equity	**5,896**	14,101	14,093
Other investments	**7,810**	7,451	6,852
Current assets	**31,688**	31,432	36,183
Deferred charges	**55,590**	60,390	72,468
Non-Utility			
Current assets	**217**	8	8
Property and equipment	**248**	249	250
Business segment held for disposal	**—**	—	—
Other assets	**640**	738	817
Total non-utility assets	**1,105**	995	1,075
Total assets	**$330,951**	$337,845	$327,529
Capitalization and Liabilities			
Capitalization			
Common stock equity			
Common stock	**$ 19,536**	$ 19,276	$ 19,004
Additional paid-in capital	**76,081**	75,347	74,581
Accumulated other comprehensive income	**22,786**	16,171	—
Retained earnings	**(1,787)**	(2,374)	8,070
Treasury stock, at cost	**(16,701)**	(16,698)	(378)
Total common stock equity	**99,915**	91,722	101,277
Redeemable cumulative preferred stock	**—**	85	12,560
Long-term debt, less current maturities	**93,000**	93,000	74,400
Total capitalization	**192,915**	184,807	188,237
Capital lease obligation	**4,963**	5,287	5,959
Current liabilities	**22,715**	38,461	38,841
Accumulated deferred income taxes	**34,009**	26,471	23,759
Unamortized investment tax credits	**2,848**	3,130	3,413
Pine Street Barge Canal site cleanup	**7,356**	8,833	10,059
Deferred credits and other	**64,655**	68,915	55,560
Non-Utility			
Current liabilities	**—**	—	—
Other liabilities	**1,490**	1,941	1,701
Total non-utility liabilities	**1,490**	1,941	1,701
Total capitalization and liabilities	**$330,951**	$337,845	$327,529

Consolidated Statements of Retained Earnings GREEN MOUNTAIN POWER CORPORATION • For the Years Ended December 31

Dollars in thousands

	2003	2002	2001
Balance at beginning of year	**$16,171**	$ 8,070	$ 493
Net income (loss)	**10,407**	11,494	11,611
	26,578	19,564	12,104
Deduct cash dividends declared			
Redeemable cumulative preferred stock	**3**	96	933
Common stock	**3,789**	3,297	3,101
Total	**3,792**	3,393	4,034
Balance at year end	**$22,786**	$16,171	$ 8,070

2000	1999	1998	1997	1996	1995	1994	1993
$291,107	$283,917	$276,853	$265,441	$248,135	$239,291	$227,991	$214,977
110,273	102,854	94,604	87,689	81,286	75,797	69,246	64,226
180,834	181,063	182,249	177,752	166,849	163,494	158,745	150,751
6,449	7,038	7,696	8,342	9,006	9,778	10,278	11,029
7,389	4,795	5,611	10,626	13,998	8,727	6,964	9,631
194,672	192,896	195,556	196,720	189,853	181,999	175,987	171,411
14,373	14,545	15,048	15,860	15,769	16,024	16,684	16,886
6,357	6,120	5,630	6,137	4,865	4,224	4,067	5,642
53,652	33,238	35,700	29,125	30,901	30,216	28,798	26,215
46,036	43,296	35,576	35,831	43,224	42,951	35,659	33,893
8	48	7,974	11,654	4,490	4,131	6,295	3,656
252	253	1,213	10,784	11,226	11,478	11,329	11,331
—	9,477	—	—	—	—	—	—
1,258	1,321	18,127	19,622	24,211	22,259	15,792	13,639
1,518	11,099	27,314	42,060	39,927	37,868	33,416	28,626
$316,608	$301,194	$314,824	$325,733	$324,539	$313,282	$294,611	$282,673
$ 18,608	$ 18,085	$ 17,711	$ 17,318	$ 16,790	$ 16,168	$ 15,592	$ 15,120
73,321	72,594	71,914	70,720	68,226	64,206	60,378	57,178
—	—	—	—	—	—	—	—
493	10,344	17,508	26,717	26,916	26,412	25,727	25,229
(378)	(378)	(378)	(378)	(378)	(378)	(378)	(378)
92,044	100,645	106,755	114,377	111,554	106,408	101,319	97,149
12,795	14,435	16,085	17,735	19,310	8,930	9,135	9,385
72,100	81,800	88,500	93,200	94,900	91,134	74,967	79,800
176,939	196,880	211,340	225,312	225,764	206,472	185,421	186,334
6,449	7,038	7,696	8,342	9,006	9,778	10,278	11,029
68,109	38,150	28,825	25,286	21,037	32,629	40,441	37,925
25,644	25,201	23,389	23,501	26,726	25,292	22,082	21,001
3,695	3,978	4,260	4,542	4,825	5,107	5,390	5,672
11,554	8,815	11,220	—	—	—	—	—
20,901	21,132	21,020	25,680	23,417	21,642	21,962	13,541
—	—	720	1,119	1,752	1,124	918	666
3,317	—	6,354	11,951	12,012	11,238	8,119	6,505
3,317	—	7,074	13,070	13,764	12,362	9,037	7,171
$316,608	$301,194	$314,824	$325,733	$324,539	$313,282	$294,611	$282,673

2000	1999	1998	1997	1996	1995	1994	1993
$10,344	$17,508	$26,717	$26,916	$26,412	$25,727	$25,229	$24,801
(5,840)	(3,063)	(2,878)	9,438	11,959	11,503	11,002	10,631
4,504	14,445	23,839	36,354	38,371	37,230	36,231	35,432
1,014	1,155	1,295	1,433	1,010	771	794	811
2,997	2,946	5,035	8,204	10,445	10,047	9,710	9,392
4,011	4,101	6,331	9,637	11,455	10,818	10,504	10,203
$ 493	$10,344	$17,508	$26,717	$26,916	$26,412	$25,727	$25,229

	2003	2002	2001
		(In thousands)	
Operating Activities:			
Income (Loss) from continuing operations before preferred dividends	**$ 10,328**	$ 11,395	$ 11,793
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**13,803**	14,151	14,294
Dividends from associated companies less equity income	**884**	45	(19)
Allowance for funds used during construction	**(654)**	(335)	(398)
Amortization of purchased power costs	**318**	3,236	3,767
Deferred income taxes	**1,479**	3,577	345
Accrued purchase power option call	**—**	—	(8,276)
Deferred purchased power costs	**(570)**	(2,003)	1,126
Rate levelization liability	**(1,121)**	(4,483)	8,527
Environmental proceedings and conservation expenditures	**(1,890)**	(2,194)	(3,380)
Changes in current assets and current liabilities	**(6,004)**	4,909	8,097
Other	**4,418**	311	(2,500)
Net cash provided by continuing operations	**20,991**	28,609	33,376
Net cash provided (used) by discontinued segment	**79**	99	(182)
Net cash provided by operating activities	**21,070**	28,708	33,194
Investing Activities:			
Construction expenditures	**(16,617)**	(19,543)	(12,963)
Investment in non-utility property	**(198)**	(206)	(212)
Proceeds from sale of subsidiaries	**—**	—	—
Investment in associated companies	**(108)**	(392)	—
Return of capital from associated companies	**7,615**	370	299
Net cash used in investing activities	**(9,308)**	(19,771)	(12,876)
Financing Activities:			
(Investment in) Maturity of certificate of deposit	**—**	—	16,173
Payments to acquire treasury stock	**(3)**	(16,320)	—
Issuance of preferred stock	**—**	—	—
Repurchase of preferred stock	**(85)**	(12,536)	(235)
Power supply option obligation	**—**	—	(16,012)
Issuance of common stock	**995**	1,037	1,655
Short-term debt, net	**(2,000)**	2,500	(15,500)
Issuance of long-term debt	**—**	42,000	12,000
Reduction in long-term debt	**(8,000)**	(25,322)	(9,700)
Cash dividends	**(3,792)**	(3,393)	(4,034)
Net cash provided by (used in) financing activities	**(12,885)**	(12,034)	(15,653)
Net increase (decrease) in cash and cash equivalents	**(1,123)**	(3,097)	4,665
Cash and cash equivalents at beginning of year	**1,909**	5,006	341
Cash and Cash Equivalents at End of Year	**$ 786**	$ 1,909	$ 5,006

2000	1999	1998	1997	1996	1995	1994	1993
$ 709	$ 3,613	($ 2,878)	$ 9,438	$ 11,959	$ 11,503	$ 11,002	$ 10,631
15,304	16,187	16,059	16,359	16,280	14,116	10,683	8,572
(26)	169	812	(90)	254	660	202	254
(512)	(224)	(235)	(672)	(643)	(574)	(803)	(630)
5,575	5,725	6,405	5,212	5,187	6,036	4,178	3,723
161	1,530	(394)	(2,997)	1,655	3,432	1,302	4,897
8,276	—	—	—	—	—	—	—
(6,692)	(6,590)	(7,830)	(331)	(5,917)	(12,935)	(536)	(6,432)
—	—	—	—	—	—	—	—
(2,073)	(8,048)	1,177	(4,534)	(4,927)	(5,311)	715	(10,608)
(9,628)	4,751	(3,822)	(2,517)	781	(595)	(4,220)	1,221
(135)	(2,008)	645	6,230	1,738	(95)	2,383	(2,537)
10,959	15,105	9,939	26,098	26,367	16,237	24,906	9,091
245	(138)	—	—	—	—	—	—
11,204	14,967	9,939	26,098	26,367	16,237	24,906	9,091
(13,853)	(9,174)	(10,900)	(16,409)	(17,541)	(15,314)	(13,536)	(15,949)
(187)	(190)	(1,442)	218	(2,203)	(6,121)	(1,220)	(5,950)
6,000	—	11,500	—	—	—	—	—
—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
(8,039)	(9,364)	(842)	(16,191)	(19,744)	(21,435)	(14,756)	(21,899)
(15,438)	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—
—	—	—	—	12,000	—	—	—
(1,640)	(1,650)	(1,650)	(1,575)	(1,620)	(205)	(250)	(190)
15,419	—	—	—	—	—	—	—
1,250	1,054	1,587	3,428	4,642	4,404	3,671	4,077
7,600	900	4,384	1,600	(7,400)	(11,799)	1,198	7,402
—	—	—	—	14,000	25,917	—	20,000
(6,700)	(1,700)	(6,767)	(4,201)	(16,201)	(4,833)	(1,800)	(8,530)
(4,011)	(4,101)	(6,332)	(9,637)	(11,455)	(10,818)	(10,504)	(10,204)
(3,520)	(5,497)	(8,778)	(10,385)	(6,034)	2,666	(7,685)	12,555
(355)	106	319	(478)	589	(2,532)	2,465	(253)
696	590	271	749	160	2,692	227	480
$ 341	$ 696	$ 590	$ 271	$ 749	$ 160	$ 2,692	$ 227

		2003	2002	2001
Common Stock Data				
Net income (loss) applicable to common stock (in thousands)	($)	**10,404**	11,398	10,678
Shares outstanding (in thousands and net of treasury shares)				
Year-end		**5,033**	4,955	5,685
Weighted average		**4,980**	5,592	5,630
Per share of common stock				
Earnings (loss) per average share (Note 1)	($)	**2.09**	2.04	1.90
Dividends paid	($)	**0.76**	0.60	0.55
Payout ratio (Note 5)	(%)	**36.4**	29.6	28.9
Net book value	($)	**19.85**	18.51	17.81
Price range N.Y.S.E.				
High	($)	**23.84**	21.08	19.50
Low	($)	**19.02**	15.75	11.06
Year-end	($)	**23.60**	20.97	18.65
Price Earnings Ratio (price at year-end) (Note 5)		**11.3**	10.3	9.8
Capitalization (in thousands)				
Common stock equity	($)	**91,915**	91,722	101,277
Redeemable cumulative preferred stock	($)	**0**	85	12,560
Long-term debt (including current maturities)	($)	**93,000**	101,000	84,100
Total	($)	**192,915**	192,807	197,937
Capitalization Ratios				
Common stock equity	(%)	**51.8**	47.6	51.2
Redeemable cumulative preferred stock	(%)	**0.0**	0.0	6.3
Long-term debt (including current maturities)	(%)	**48.2**	52.4	42.5
Total	(%)	**100.0**	100.0	100.0
Other Financial Ratios				
Long-term debt weighted average annual interest rate	(%)	**7.0**	7.0	7.1
Preferred stock weighted average annual dividend rate	(%)	**—**	4.8	7.3
Income before interest and income taxes to long-term debt interest		**3.2**	4.5	4.2
Income before interest and after income taxes to long-term debt interest		**2.5**	3.4	3.1
Income before interest and after income taxes to total interest charges and preferred dividends		**2.5**	2.8	2.3
Operating revenues as a % of net utility property (year-end) (Note 2)	(%)	**119.5**	115.6	134.4
Operating expenses (excluding income taxes) as a % of operating revenues	(%)	**92.7**	92.3	91.7
Annual depreciation expense as a % of depreciable property	(%)	**3.2**	3.2	3.5
Accumulated depreciation as a % of depreciable property	(%)	**33.9**	32.8	39.4
Return on average common equity (Note 3)	(%)	**10.8**	11.0	11.0
Internally generated funds as a % of capital requirements, sinking fund obligations and other requirements (Note 4)	(%)	**76.2**	67.8	91.9
AFUDC as a % of net income (loss) applicable to common stock	(%)	**6.3**	2.9	3.7

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) Presented as a three-year average, net of dividend payments.
(5) Measure is not meaningful for years with net loss.

	2000	1999	1998	1997	1996	1995	1994	1993
	(6,854)	(4,218)	(4,173)	8,005	10,949	10,732	10,208	9,820
	5,567	5,410	5,297	5,180	5,021	4,835	4,662	4,520
	5,491	5,361	5,243	5,112	4,933	4,747	4,588	4,457
	(1.25)	(0.79)	(0.80)	1.57	2.22	2.26	2.23	2.20
	0.55	0.55	0.9625	1.61	2.12	2.12	2.12	2.11
	—	—	—	102.5	95.5	93.8	95.1	95.9
	16.53	18.60	20.15	22.08	22.22	22.01	21.73	21.49
	12-13/16	14	20-1/16	26-1/4	29-1/8	28-5/8	31-1/4	36-5/8
	6-7/8	7-1/8	10-1/16	17-5/8	22-3/4	23-7/8	23-3/8	30-3/4
	12-1/2	7-7/16	10-1/2	18-3/8	23-7/8	27-3/4	27-7/8	31
	—	—	—	12.0	11.0	12.0	13.0	14.0
	92,044	100,645	106,755	114,377	111,554	106,408	101,319	97,149
	12,795	14,435	16,085	17,735	19,310	8,930	9,135	9,385
	81,800	88,500	90,200	94,900	97,934	98,967	79,800	81,600
	186,639	203,580	213,040	227,012	228,798	214,305	190,254	188,134
	49.3	49.4	50.1	50.4	48.8	49.7	53.3	51.6
	6.9	7.1	7.6	7.8	8.4	4.2	4.8	5.0
	43.8	43.5	42.3	41.8	42.8	46.1	41.9	43.4
	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	7.5	7.5	7.6	7.7	8.1	9.0	8.7	9.4
	7.5	7.5	7.5	7.6	8.8	8.5	8.5	8.5
	0.1	0.8	0.5	3.3	3.8	3.7	3.4	3.6
	0.2	0.6	0.7	2.3	2.8	2.9	2.6	2.7
	0.2	0.5	0.5	1.9	2.3	2.3	2.3	2.3
	132.7	115.2	80.7	75.1	78.9	73.4	69.5	71.4
	98.4	96.3	97.8	87.3	87.4	87.1	86.6	85.7
	3.5	3.3	3.4	3.2	3.3	3.3	3.2	3.2
	37.9	36.2	36.2	34.9	34.5	33.8	32.4	31.8
	(7.1)	(4.0)	(3.8)	7.1	10.0	10.3	10.3	10.3
	59.4	89.0	64.6	129.4	38.8	58.0	83.7	46.2
	(7.5)	(5.3)	(5.6)	8.4	5.9	5.3	7.9	6.4

Dollars in thousands	2003	2002	2001
Number of Active Employees full and part time, at December 31,			
—Green Mountain Power	**196**	194	193
—Subsidiaries	**0**	0	0
Utility Plant Investment (year-end)			
Intangible	**$ 14,091**	$ 12,580	$ 14,214
Steam production	**10,649**	10,649	10,609
Hydro production	**31,736**	31,518	30,581
Other production	**26,147**	24,746	21,924
Transmission	**37,093**	36,846	35,734
Distribution	**178,292**	170,655	163,930
General	**26,893**	24,549	25,496
Total utility plant investment	**324,901**	311,543	302,488
Less accumulated depreciation	**110,112**	102,250	119,053
Net utility plant	**214,789**	209,293	183,435
Property under capital lease	**5,047**	5,287	5,959
Construction work in progress	**9,026**	8,896	7,464
Total utility plant investment, net	**$228,862**	$223,476	$196,858
Beginning balance—utility plant	**$311,543**	$302,488	$291,107
Transfers to utility plant from CWIP	**16,314**	17,701	13,927
Retirements from utility plant	**(2,956)**	(8,646)	(2,546)
Ending balance—utility plant	**$324,901**	$311,543	$302,488
Beginning balance—construction work in progress	**$ 8,896**	$ 7,464	$ 7,389
Construction expenditures, net of customer advances	**16,444**	19,133	14,002
Transfers to utility plant	**(16,314)**	(17,701)	(13,927)
Ending balance—construction work in progress	**$ 9,026**	$ 8,896	$ 7,464
Sales of Securities (gross proceeds)			
Long-term debt	**$ —**	$ 42,000	$ 12,000
Common stock (excludes DRIP, ESIP, PAYSOP, restricted shares and stock grants)	**—**	—	—
Redeemable cumulative preferred stock	**—**	—	—
Total sales of securities	**$ —**	$ 42,000	$ 12,000

2000	1999	1998	1997	1996	1995	1994	1993
197	196	288	321	344	350	373	387
5	5	6	48	45	50	59	58
$ 11,726	$ 11,276	$ 10,206	$ 9,168	$ 6,330	$ 7,451	$ 6,415	$ 4,571
10,525	10,460	10,782	10,702	10,702	10,799	10,752	10,748
29,728	29,667	29,435	29,200	28,771	26,315	25,757	24,930
21,833	22,141	22,217	22,862	18,239	18,393	18,427	18,402
35,100	34,793	34,924	33,878	30,356	29,837	29,344	28,698
157,959	151,873	145,694	136,825	131,626	124,330	116,325	107,489
24,236	23,707	23,595	22,806	22,111	22,166	20,971	20,139
291,107	283,917	276,853	265,441	248,135	239,291	227,991	214,977
110,273	102,854	94,604	87,689	81,286	75,797	69,246	64,226
180,834	181,063	182,249	177,752	166,849	163,494	158,745	150,751
6,449	7,038	7,696	8,342	9,006	9,778	10,278	11,029
7,389	4,794	5,611	10,626	13,998	8,727	6,964	9,631
$194,672	$192,895	$195,556	$196,720	$189,853	$181,999	$175,987	$171,411
$283,917	$276,853	$265,441	$248,135	$239,291	$227,991	$214,977	$201,643
11,258	9,990	15,927	20,222	12,522	13,403	16,204	15,223
(4,068)	(2,926)	(4,515)	(2,916)	(3,678)	(2,103)	(3,190)	(1,889)
$291,107	$283,917	$276,853	$265,441	$248,135	$239,291	$227,991	$214,977
$ 4,794	$ 5,611	$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631	$ 9,646
13,853	9,173	10,912	16,850	17,793	15,166	13,537	15,208
(11,258)	(9,990)	(15,927)	(20,222)	(12,522)	(13,403)	(16,204)	(15,223)
$ 7,389	$ 4,794	$ 5,611	$ 10,626	$ 13,998	$ 8,727	$ 6,964	$ 9,631
$ —	$ —	$ —	$ —	$ 14,000	$ 24,000	$ —	$ 20,000
—	—	—	—	—	—	—	—
—	—	—	—	12,000	—	—	—
$ —	$ —	$ —	$ —	$ 26,000	$ 24,000	$ —	$ 20,000

	2003	2002	2001
Net System Capability During Peak Month (MW*)			
Total capability (MW)	**393.9**	406.9	408.0
Net system peak	**330.2**	342.0	341.2
Reserve (MW)	**63.7**	64.9	66.8
Reserve % of peak	**19.3%**	19.0%	19.6%
Net Production (MWH)**			
Hydro	**838,855**	901,998	951,146
Lease transmissions	**—**	—	—
Nuclear	**884,585**	771,781	736,420
Conventional steam	**2,524,233**	2,431,115	2,670,249
Internal combustion	**12,603**	4,090	18,291
Combined cycle	**68,488**	81,362	72,653
Wind	**10,828**	11,458	12,135
Total production	**4,339,592**	4,201,804	4,460,894
Less nonrequirements sales to other utilities	**2,284,003**	2,104,172	2,365,809
Production for requirements sales	**2,055,589**	2,097,632	2,095,085
Less requirements sales and lease transmissions (MWH)	**1,937,376**	1,951,959	1,956,232
Losses and Company use (MWH)	**118,213**	145,673	138,853
Losses as a % of total production	**2.72%**	3.47%	3.11%
System load factor (***)	**71.1%**	70.0%	70.1%
Sales and Lease Transmissions (MWH)**			
Residential—GMP	**581,047**	553,294	549,151
Lease MWH transmitted	**—**	—	—
Total residential	**581,047**	553,294	549,151
Commercial & industrial–small	**703,036**	695,418	691,027
Commercial & industrial–large	**645,271**	689,704	710,944
Other	**4,986**	9,773	2,030
Total retail sales and lease transmissions	**1,934,340**	1,948,189	1,953,154
Sales to Municipals & Cooperatives (Rate W)	**3,036**	3,770	3,078
Total Requirements Sales	**1,937,376**	1,951,959	1,956,232
Other Sales for Resale	**2,284,003**	2,104,172	2,365,809
Total sales and lease transmissions	**4,221,379**	4,056,131	4,322,041
Average Number of Electric Customers			
Residential	**74,693**	73,861	73,249
Commercial & industrial–small	**13,340**	13,173	12,984
Commercial & industrial–large	**23**	21	22
Other	**65**	65	65
Total	**88,127**	87,120	86,320
Average Revenue Per KWH (Cents)			
Residential including lease revenues	**12.90**	12.96	13.33
Lease charges	**—**	—	—
Total residential	**12.90**	12.96	13.33
Commercial & industrial–small	**10.46**	10.44	10.90
Commercial & industrial–large	**7.41**	7.31	7.70
Total retail including lease revenues	**10.22**	10.09	10.44
Average Use and Revenue Per Residential Customer			
KWH including lease transmissions	**7,779**	7,491	7,497
Revenues including lease revenues	**$1,003**	$971	$999

*MW—Megawatt is one thousand kilowatts.

**MWH—Megawatthour is one thousand kilowatthours.

2000	1999	1998	1997	1996	1995	1994	1993
411.1	393.2	396.9	416.9	425.8	396.1	438.2	474.7
323.5	317.9	312.5	311.5	313.0	297.1	308.3	307.3
87.6	75.3	84.4	105.4	112.8	99.0	129.9	167.4
27.1%	23.7%	27.0%	33.8%	36.0%	33.3%	42.1%	54.5%
1,053,223	1,095,738	972,723	1,073,246	1,192,881	1,043,617	742,088	751,078
—	—	—	—	—	—	—	15,425
803,303	731,431	607,708	772,030	680,613	682,814	763,690	598,245
2,704,427	2,328,267	750,602	560,504	705,331	673,982	651,105	748,626
35,699	12,312	40,148	4,827	2,674	6,646	3,532	2,849
73,433	99,962	118,322	104,836	51,162	92,723	37,808	40,966
12,246	7,956	—	—	—	—	—	—
4,682,331	4,275,666	2,489,503	2,515,443	2,632,661	2,499,782	2,198,223	2,157,189
2,573,576	2,152,781	499,409	524,192	663,175	582,942	328,794	271,224
2,108,755	2,122,885	1,990,094	1,991,251	1,969,486	1,916,840	1,869,429	1,885,965
1,954,898	1,920,257	1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454
153,857	202,628	106,134	120,338	155,115	156,010	138,932	136,511
3.29%	4.74%	4.26%	4.78%	5.89%	6.24%	6.32%	6.33%
74.2%	76.2%	72.7%	73.0%	71.6%	73.7%	69.2%	70.1%
558,682	544,447	533,904	549,259	557,726	549,296	564,635	541,579
—	—	—	—	—	—	—	15,425
558,682	544,447	533,904	549,259	557,726	549,296	564,635	557,004
704,126	688,493	665,707	645,331	630,839	608,688	604,686	593,560
683,296	664,110	636,436	608,051	584,249	556,278	521,400	529,372
6,713	3,138	3,476	3,939	2,898	8,855	1,146	8,868
1,952,817	1,900,188	1,839,522	1,806,580	1,775,712	1,723,117	1,691,867	1,688,804
2,081	20,069	44,437	64,333	38,659	37,713	38,630	60,650
1,954,898	1,920,257	1,883,959	1,870,913	1,814,371	1,760,830	1,730,497	1,749,454
2,573,576	2,152,781	499,409	524,192	663,175	582,942	328,794	271,224
4,528,474	4,073,038	2,383,368	2,395,105	2,477,546	2,343,772	2,059,291	2,020,678
72,424	71,515	71,301	70,671	70,198	69,659	68,811	67,994
12,746	12,438	12,170	11,989	11,828	11,712	11,611	11,447
23	23	23	23	25	24	24	25
65	66	70	75	75	76	76	74
85,258	84,042	83,564	82,758	82,126	81,471	80,522	79,540
12.50	12.32	11.56	11.18	10.87	10.09	9.03	8.94
—	—	—	—	—	—	—	.06
12.50	12.32	11.56	11.18	10.87	10.09	9.03	9.00
10.00	9.88	9.29	9.10	8.96	8.42	8.00	7.97
6.51	6.55	6.32	6.22	6.28	5.86	6.02	5.96
9.52	9.47	8.96	8.79	8.72	8.36	7.96	7.86
7,717	7,617	7,488	7,772	7,945	7,885	8,206	8,192
$965	$938	$865	$869	$863	$796	$741	$733

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

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(888)921-5537

Shareholder services over the web:

You may access your GMP shareholder account online by visiting the Transfer Agent's website at www.melloninvestor.com. Click on "Investor ServiceDirect." You will be able to:

- Obtain duplicate 1099 tax form
- View payment history for dividends
- Make address changes
- View account status
- View certificate history
- View book-entry information

Click on "Investor" to receive information on:

- Transfer ownership of stock
- Dividend reinvestment plan information
- Obtain various forms for stock powers and dividend order forms

For Technical Assistance please call 1-877-978-7778 between 9 a.m. - 7 p.m. Monday-Friday EST.

Shareholder services involving stock transfers, lost certificates, dividend problems, address changes or dividend reinvestment:
Mellon Investor Services, L.L.C.
85 Challenger Road
Ridgefield Park, NJ 07660
(888)921-5537

Annual Report on Form 10-K

A copy of the 2003 Annual Report on Form 10-K filed with the Securities and Exchange Commission is available upon request to the Corporate Secretary.

Common Stock Listing:
New York Stock Exchange
Symbol: GMP

Dividend Schedule for 2004 (approximate)

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

Bond Ratings as of December 31, 2003 (See page 18 for details)

	Fitch	Moody's	S&P
First Mortgage Bonds	BBB+	Baa1	BBB

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. Participants in the Plan may make optional cash investments of not less than $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 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.

2004 Annual Shareholders Meeting

All shareholders are invited to attend GMP's Annual Meeting on Thursday, May 20, 2004 at Green Mountain Power, 163 Acorn Lane, Colchester, Vermont. The meeting will begin at 1 p.m.

GREEN MOUNTAIN POWER

163 Acorn Lane
Colchester, Vermont 05446

www.greenmountainpower.biz