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GREEN MOUNTAIN POWER CORP
Form 10-Q
November 07, 2003

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE
ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2003

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE
ACT OF 1934
FOR THE TRANSITION PERIOD FROM _____ TO _____

COMMISSION FILE NUMBER 1-8291

GREEN MOUNTAIN POWER CORPORATION

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

VERMONT 03-0127430

(STATE OR OTHER JURISDICTION OF INCORPORATION (I.R.S. EMPLOYER
IDENTIFICATION NO.)
OR ORGANIZATION)

163 ACORN LANE
COLCHESTER, VT 05446

ADDRESS OF PRINCIPAL EXECUTIVE OFFICES (ZIP CODE)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE (802) 864-5731

INDICATE BY CHECK MARK WHETHER THE REGISTRANT (1) HAS FILED ALL REPORTS
REQUIRED TO BE FILED BY SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF
1934 DURING THE PRECEDING 12 MONTHS (OR FOR SUCH SHORTER PERIOD THAT THE
REGISTRANT WAS REQUIRED TO FILE SUCH REPORTS), AND (2) HAS BEEN SUBJECT TO SUCH
FILING REQUIREMENTS FOR THE PAST 90 DAYS. YES X NO

Indicate the number of shares outstanding of each of the issuer's classes of
common stock, as of the latest practicable date.

CLASS - COMMON STOCK	OUTSTANDING AT OCTOBER 31, 2003
\$3.33 1/3 PAR VALUE	5,000,407

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This report contains statements that may be considered forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934. You can identify these statements by forward-looking words such as "may," "could," "should," "would," "intend," "will," "expect," "anticipate," "believe," "estimate," "continue" or similar words. We intend these forward-looking statements to be covered by the safe harbor provisions for forward-looking statements contained in the Private Securities Reform Act of 1995 and are including this statement for purposes of complying with these safe harbor provisions. You should read statements that contain these words carefully because they discuss the Company's future expectations, contain projections of the Company's future results of operations or financial condition, or state other "forward-looking" information.

There may be events in the future that we are not able to predict accurately or control and that may cause actual results to differ materially from the expectations described in forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainties, and actual results may differ materially from those discussed in this document, including the documents incorporated by reference in this document. These differences may be the result of various factors, including changes in general, national, regional, or local economic conditions, changes in fuel or wholesale power supply costs, regulatory or legislative action or decisions, and other risk factors identified from time to time in our periodic filings with the Securities and Exchange Commission.

The factors referred to above include many, but not all, of the factors that could impact the Company's ability to achieve the results described in any forward-looking statements. You should not place undue reliance on forward-looking statements. You should be aware that the occurrence of the events described above and elsewhere in this document, including the documents incorporated by reference, could harm the Company's business, prospects, operating results or financial condition. We do not undertake any obligation to update any forward-looking statements as a result of future events or developments.

AVAILABLE INFORMATION

Our Internet website address is: www.Greenmountainpower.biz. We make available free of charge through the website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The information on our website is not, and shall not be deemed to be, a part of this report or incorporated into any other filings we make with the SEC.

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INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES AT AND FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2003 AND 2002

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

GREEN MOUNTAIN POWER CORPORATION CONSOLIDATED COMPARATIVE INCOME STATEMENTS

	UNAUDITED			
	THREE MONTHS ENDED SEPTEMBER 30 2003	ENDED 2002	NINE MONTHS SEPTEMBER 2003	2002
(in thousands, except per share data)				
OPERATING REVENUES	\$71,975	\$73,477	\$209,376	\$209,376
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation	9,297	10,713	28,582	28,582
Company-owned generation	1,577	1,847	6,061	6,061
Purchases from others	39,421	40,622	111,799	111,799
Other operating	4,893	3,400	13,080	13,080
Transmission	3,417	3,707	10,963	10,963
Maintenance	1,985	2,082	6,012	6,012
Depreciation and amortization	3,403	3,608	10,354	10,354
Taxes other than income	1,860	1,964	5,819	5,819
Income taxes	1,820	1,789	4,746	4,746

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Total operating expenses.	67,673	69,732	197,416	19
OPERATING INCOME	<u>4,302</u>	<u>3,745</u>	<u>11,960</u>	<u>1</u>
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations.	407	1,362	1,233	
Allowance for equity funds used during construction.	103	53	279	
Other income (deductions), net	(21)	(612)	92	
TOTAL OTHER INCOME.	<u>489</u>	<u>803</u>	<u>1,604</u>	
INTEREST CHARGES				
Long-term debt	1,762	1,253	5,278	
Other interest	67	272	234	
Allowance for borrowed funds used during construction.	(73)	(23)	(190)	
TOTAL INTEREST CHARGES.	<u>1,756</u>	<u>1,502</u>	<u>5,322</u>	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS				
Dividends on preferred stock	1	4	3	
Income from continuing operations.	3,034	3,042	8,239	
Income (loss) from discontinued segment, including provisions for operating losses during phaseout period.	6		(15)	
NET INCOME APPLICABLE TO COMMON STOCK.	<u>\$ 3,040</u>	<u>\$ 3,042</u>	<u>\$ 8,224</u>	<u>\$</u>

UNAUDITED

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	THREE MONTHS ENDED		NINE MONTHS ENDED	
	SEPTEMBER 30		SEPTEMBER 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
Net income.	\$3,040	\$3,042	\$8,224	\$8,273
Comprehensive income.	-	-	-	-
Other comprehensive income, net of tax.	<u>\$3,040</u>	<u>\$3,042</u>	<u>\$8,224</u>	<u>\$8,273</u>
Basic earnings per share	\$ 0.61	\$ 0.53	\$ 1.65	\$ 1.45
Diluted earnings per share	0.59	0.52	1.60	1.41
Cash dividends declared per share.	\$ 0.19	\$ 0.14	\$ 0.57	\$ 0.41
Weighted average common shares outstanding-basic	4,982	5,723	4,970	5,709
Weighted average common shares outstanding-diluted	5,141	5,879	5,130	5,874

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

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GREEN MOUNTAIN POWER CORPORATION CONSOLIDATED STATEMENTS OF CASH FLOWS	For the Nine Months Ended September 30	
	2003	2002

OPERATING ACTIVITIES:	(in thousands)	
Net income before preferred dividends	\$ 8,227	\$ 8,372
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,354	10,547
Dividends from associated companies less equity income.	120	(1,024)
Allowance for funds used during construction.	(469)	(253)
Amortization of deferred purchased power costs.	(1,135)	2,385
Deferred income taxes	827	3,068
Deferred purchased power costs.	(130)	(1,982)
Rate levelization liability	119	(5,519)
Conservation deferrals, net	(339)	(312)
Changes in:		
Accounts receivable and accrued utility revenues.	1,367	2,223
Prepayments, fuel and other current assets.	(1,726)	1,928
Accounts payable and other current liabilities.	(4,948)	(1,117)
Accrued income taxes payable and receivable	2,521	1,458
Other	358	84

Net cash provided by operating activities	15,144	19,858
INVESTING ACTIVITIES:		
Construction expenditures	(11,986)	(14,127)
Environmental expenditures, net	(1,307)	(1,102)
Investment in Associated Companies.	(108)	(392)
Investment in nonutility property	(151)	(134)

Net cash used in investing activities	(13,552)	(15,755)
FINANCING ACTIVITIES:		
Payments to acquire treasury stock.	(3)	-
Repurchase of preferred stock	-	(12,325)
Issuance of common stock.	356	616
Reduction in long-term debt	-	(5,100)
Short-term debt, net.	(1,000)	11,000
Cash dividends.	(2,836)	(2,455)

Net cash used in financing activities	(3,482)	(8,264)
Net increase (decrease) in cash and cash equivalents.	(1,890)	(4,161)
Cash and cash equivalents at beginning of period.	1,909	5,006

Cash and cash equivalents at end of period.	\$ 19	\$ 845
	=====	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for: Interest (net of amounts capitalized) \$	4,588	\$ 4,738
Income taxes.	2,163	2,349

SUPPLEMENTAL DISCLOSURE OF NON-CASH INFORMATION:

A capital lease obligation of \$181 was incurred when the Company entered into a lease for new office furniture during February 2003.

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

GREEN MOUNTAIN POWER CORPORATION		UNAUDITED		
CONSOLIDATED BALANCE SHEETS		-----	-----	-----
		SEPTEMBER 30	2002	DECEMBER 31, 2001
		2003	2002	2001
		-----	-----	-----
		(in thousands)		
ASSETS				
UTILITY PLANT				
	Utility plant, at original cost	\$ 314,685	\$308,830	\$311,111
	Less accumulated depreciation	131,409	124,811	122,111
	Net utility plant	183,276	184,019	189,000
	Property under capital lease	5,654	5,959	5,959
	Construction work in progress	17,795	12,293	8,111
	Total utility plant, net	206,725	202,271	203,070
OTHER INVESTMENTS				
	Associated companies, at equity	14,108	15,469	14,108
	Other investments	7,494	7,235	7,494
	Total other investments	21,602	22,704	21,602
CURRENT ASSETS				
	Cash and cash equivalents	19	845	1,111
	Accounts receivable, less allowance for doubtful accounts of \$634, \$613 and \$547	16,582	15,853	17,111
	Accrued utility revenues	5,921	4,900	6,111
	Fuel, materials and supplies, at average cost	4,567	3,261	3,111
	Prepayments	2,352	925	1,111
	Other	460	389	460
	Total current assets	29,901	26,173	31,000
DEFERRED CHARGES				
	Demand side management programs	6,588	6,598	6,588
	Purchased power costs	3,622	3,139	2,111
	Pine Street Barge Canal	13,019	12,425	13,019
	Power supply derivative deferral	16,780	31,776	18,111
	Other	9,544	13,829	11,111
	Total deferred charges	49,553	67,767	51,000
NON-UTILITY				
	Other current assets	8	8	8
	Property and equipment	249	250	249
	Other assets	666	739	666
	Total non-utility assets	923	997	923
TOTAL ASSETS		\$ 308,704	\$319,912	\$309,000

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

GREEN MOUNTAIN POWER CORPORATION CONSOLIDATED BALANCE SHEETS	UNAUDITED		
	SEPTEMBER 30 2003	2002	DECEMBER 31 2002
(in thousands except share data)			
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION			
Common stock, \$3.33 1/3 par value, authorized 10,000,000 shares (issued 5,817,246 ,5,743,296 and 5,782,496)	\$ 19,391	\$ 19,145	\$ 19,276
Additional paid-in capital.	75,587	75,057	75,347
Retained earnings	21,562	13,987	16,171
Accumulated other comprehensive income.	(2,374)	-	(2,374)
Treasury stock, at cost (827,639 and 15,856 shares)	(16,701)	(428)	(16,698)
Total common stock equity	97,465	107,761	91,722
Redeemable cumulative preferred stock	55	85	55
Long-term debt, less current maturities	93,000	59,000	93,000
Total capitalization.	190,520	166,846	184,777
CAPITAL LEASE OBLIGATION.	5,601	5,959	5,287
CURRENT LIABILITIES			
Current maturities of preferred stock	30	150	30
Current maturities of long-term debt.	8,000	8,000	8,000
Short-term debt	1,500	23,000	2,500
Accounts payable, trade and accrued liabilities	5,506	6,152	7,431
Accounts payable to associated companies.	4,801	8,810	8,940
Rate levelization liability	4,210	3,008	4,091
Accrued income taxes.	7,105	1,032	4,583
Customer deposits	869	822	898
Interest accrued.	1,960	1,327	1,081
Other	1,203	1,112	937
Total current liabilities	35,184	53,413	38,491
DEFERRED CREDITS			
Power supply derivative liability	16,780	32,616	18,405
Accumulated deferred income taxes	27,510	27,040	26,471
Unamortized investment tax credits.	2,918	3,201	3,130
Pine Street Barge Canal cleanup liability	7,525	8,957	8,833
Other	20,844	19,510	21,767
Total deferred credits.	75,577	91,324	78,606
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Net liabilities of discontinued segment	1,822	2,370	1,941
Total non-utility liabilities	1,822	2,370	1,941

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TOTAL CAPITALIZATION AND LIABILITIES.	\$308,704	\$319,912	\$309,102
	=====	=====	=====

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS In thousands	UNAUDITED			
	THREE MONTHS ENDED	THREE MONTHS ENDED	NINE MONTHS ENDED	NINE MONTHS ENDED
	SEPTEMBER 30 2003	SEPTEMBER 30 2002	SEPTEMBER 30 2003	SEPTEMBER 30 2002
	-----	-----	-----	-----
Balance - beginning of period.	\$19,469	\$11,683	\$16,171	\$ 8,070
Net Income	3,041	3,046	8,227	8,372
Other		50		-
Cash Dividends-redeemable cumulative preferred stock	(1)	(4)	(3)	(99)
Cash Dividends-common stock.	(947)	(788)	(2,833)	(2,356)
	-----	-----	-----	-----
Balance - end of period.	\$21,562	\$13,987	\$21,562	\$13,987
	=====	=====	=====	=====

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2003

PART I-ITEM 1

1. SIGNIFICANT ACCOUNTING POLICIES

It is our opinion that the financial information contained in this report reflects all normal, recurring adjustments necessary to present a fair statement of results for the periods reported, but such results are not necessarily indicative of results to be expected for the year due to the seasonal nature of our business and include other adjustments discussed elsewhere in this report necessary to reflect fairly the results of the interim periods. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. However, the disclosures herein, when read with the Green Mountain Power Corporation (the "Company" or "GMP") annual report for 2002 filed on Form 10-K, are adequate to make the information presented not misleading.

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, and the defined benefit plan assumptions used to determine plan liabilities for our defined benefit retirement plans. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

The Vermont Public Service Board ("VPSB"), the regulatory commission in Vermont, sets the rates we charge our customers for their electricity. In

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periods prior to April 2001, we charged our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These were called seasonally differentiated rates. Seasonal rates were eliminated in April 2001, and generated approximately \$8.5 million of revenues deferred in 2001, of which \$4.4 million was recognized during 2002. The remaining \$4.1 million will be used to offset increased costs or write off regulatory assets during 2003 or 2004.

The Company operates under a rate cap which requires the deferral of revenue in periods where the Company earns more than its allowed rate of return. Conversely, previously deferred revenue is recognized in periods when the Company is not achieving its allowed return. During the three months ended September 2002, approximately \$1.2 million of previously deferred revenue was recognized in order for the Company to achieve its allowed rate of return. Due to an improvement in operating results for the quarter ended September 30, 2003, compared with the same period in 2002, the Company did not recognize or defer any revenue based on the expectation that it will achieve its return on equity. For the nine months ended September 30, 2003 the Company did not recognize nor defer any revenues, compared with \$5.5 million of previously deferred revenue recognized during the nine months ended September 30, 2002.

Certain line items on the prior year's financial statements have been reclassified for consistent presentation with the current year.

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

The Company applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for its stock option plan and has adopted the disclosure-only provisions of SFAS 123, "Accounting for Stock-Based Compensation" as amended by SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - and amendment of SFAS 123", for options issued prior to 2003. The Company now applies the accounting provisions of SFAS 123 to options granted on or after January 1, 2003. The following table illustrates the effect on net income and earnings per share as if the fair value method had been applied to all outstanding and unvested awards in each period. The fair value of options at date of grant was estimated using the Black-Scholes option-pricing model. Had the Company expensed stock-based compensation under SFAS 123 for options granted prior to 2003, the Company's diluted earnings would have been reduced by \$0.01 and \$0.02 per share for the three and nine months ended September 30, 2003, respectively.

Pro-forma net income	Three months ended September 30		Nine months ended September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
In thousands, except per share amounts				
Net income reported.	\$3,040	\$3,042	\$8,224	\$8,273
Pro-forma net income	3,000	2,997	8,103	8,137
Earnings per share				
As reported-basic.	0.61	0.53	1.65	1.45
Pro-forma basic.	0.60	0.52	1.63	1.43
As reported-diluted.	0.59	0.52	1.60	1.41
Pro-forma diluted.	0.58	0.51	1.58	1.39

UNREGULATED OPERATIONS

Our wholly owned subsidiaries are Northern Water Resources, Inc. ("NWR"); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; Green Mountain Power Investment Company ("GMPIC"); and Green Mountain Resources, Inc. ("GMRI"). We also have a rental water heater program

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that is not regulated by the VPSB. The results of these subsidiaries, excluding NWR, and the Company's unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other (Deductions) Income section of the Consolidated Statements of Income.

2. INVESTMENT IN ASSOCIATED COMPANIES

We recognize net income from our affiliates (companies in which we have ownership interests) listed below based on our percentage ownership (equity method).

VERMONT YANKEE NUCLEAR POWER CORPORATION ("VY" OR "VERMONT YANKEE")
PERCENT OWNERSHIP: 19.0% COMMON

	Three months ended September 30		Nine months ended September 30	
	2003	2002	2003	2002
(in thousands)				
Gross Revenue	\$45,342	\$48,534	\$142,324	\$134,029
Net Income Applicable	762	5,911	\$ 2,169	8,860
to Common Stock				
Equity in Net Income	145	1,111	412	1,682

On July 31, 2002, Vermont Yankee completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy"). In addition to the sale of the generating plant, the transaction calls for Entergy, 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. The Company owns approximately 19 percent of the common stock of VY. The benefits to the Company from the plant sale and the VY power contract with Entergy include:

VY received cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.

VY and its owners no longer bear operating risks associated with running the plant.

VY and its owners no longer bear the risks associated with the eventual decommissioning of the plant.

Prices under the Power Purchase Agreement between VY and Entergy (the "PPA") range from \$39 to \$45 per megawatt-hour for the period beginning January 2003, substantially lower than the forecasted cost of continued ownership and operation by VY. Contract prices ranged from \$49 to \$55 for 2002, higher than the forecasted cost of continued ownership for 2002.

The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract 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 Entergy plant.

The Company received its share of the Vermont Yankee sale proceeds, approximately \$8.2 million, in October 2003.

The sale required various regulatory approvals, all of which were granted on terms acceptable to the parties to the transaction. Certain intervener parties to the VPSB approval proceeding appealed the VPSB approval to the Vermont Supreme Court. The Vermont Supreme Court affirmed the VPSB approval in July 2003.

VERMONT ELECTRIC POWER COMPANY, INC. ("VELCO")

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Percent ownership: 28.42% common
 30.0% preferred

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 various electric utilities, including the Company, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to those using VELCO's transmission system.

	Three months ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
(in thousands)				
Gross Revenue	\$5,889	\$5,012	\$17,159	\$16,808
Net Income	288	261	910	774
Equity in Net Income.	87	70	284	239

3. COMMITMENTS AND CONTINGENCIES

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 comply with these requirements and that there are no outstanding material complaints about the Company's compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

PINE STREET BARGE CANAL SITE

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

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

As of September 30, 2003, our total expenditures related to the Pine Street site since 1982 were approximately \$29.7 million. This includes amounts not recovered in rates, amounts recovered in rates, and amounts for which rate recovery has been sought but which are presently waiting further VPSB action. A major part of the expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals of a more expensive remedy at the site, litigation and related costs necessary to obtain settlements with insurers and other PRPs to provide amounts required to fund the clean up ("remediation costs"), and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related

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response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be \$13.0 million through 2033. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset, and we believe that it is probable that we will receive future revenues to recover these costs.

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

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

On July 13, 2003, the Company and the Department entered into a Memorandum of Understanding relating primarily to the Company's rates and allowed rate of return through 2006. The Memorandum of Understanding provides for recovery of Pine Street costs over a twenty-year period without a return. The Memorandum of Understanding has not yet been approved by the VPSB. See the discussion under 2003 Proposed Rate Plan below for further details.

1998 RETAIL RATE CASE

On January 23, 2001, the VPSB approved a final settlement of the Company's 1998 rate case. The VPSB Order approving the settlement contained the following provisions:

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 Quebec 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

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successfully replaced 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 was available to be used 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 a 1997 rate case;

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;

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 \$4.4 million less than its allowed rate of return during 2002 before including in earnings deferred revenues in the same amount.

On October 10, 2002, the VPSB issued an order approving the Company's request to issue long-term debt, with the proceeds to be used to repay existing intermediate term indebtedness and short-term debt outstanding under the Company's revolving credit facility. The Company used proceeds of a \$42 million long-term debt issue in December 2002 to repurchase equity and to replace all short-term borrowings, satisfying the conditions in the VPSB final settlement order and permitting the Company to raise its dividend.

2003 PROPOSED RATE PLAN

The VPSB, in its order approving VY's sale of its nuclear power plant to Entergy, ordered the Company and Central Vermont Public Service Corporation each to file on or before April 15, 2003, a cost-of-service study based on actual 2002 data, to enable the VPSB to determine whether an adjustment to rates is justified in 2003 or 2004. The Company filed its study on April 15, 2003.

On July 11, 2003, after the Department completed its review of the Company's cost-of-service filing, the Company and the Department entered into a Memorandum of Understanding (the "Memorandum") regarding the Company's rates and allowed return on equity through the end of 2006. The Memorandum is subject to approval by the VPSB, and provides, among other things, the following:

Rate Stability: The Company's rates will remain unchanged until January 1, 2005, when they will increase by 1.9 percent, and an additional rate increase of 0.9 percent will be effective January 1, 2006, subject to the requirement that the Company file a cost of service filing with the Department and the VPSB 60 days prior to each rate increase that supports such increase. 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 requirement, the Company will implement the lesser rate increases.

Earnings Cap: The Memorandum provides that the Company will reduce its current 11.25 percent allowed return on equity to 10.50 percent for 2003, 2004, 2005 and 2006. The Memorandum further provides that the Company may carry forward any remaining deferred revenue at December 31, 2003, through 2004 to offset increased costs or reduce regulatory assets. If the Company earns in excess of its earning cap, then any 2003 or 2004 excess earnings shall be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 shall be refunded to customers as a credit on customer bills or applied to reduce regulatory assets as the Department directs.

Redesign of Rates: Within 60 days of the Board's approval of the Memorandum, the Company shall file with the Board a fully allocated cost of service study and rate redesign, which will allocate the Company's revenue

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requirement among all customer classes on the basis of current costs. Such a rate redesign will be subject to VPSB approval.

Alternative Regulation Plan: The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted by the Vermont legislature in 2003, within 120 days after Board approval of the Memorandum. If the Company and the Department agree on such a plan, and it is approved by the VPSB, the plan would supersede the terms of the Memorandum.

Amortization of Regulatory Assets: Under the Memorandum, amortization (recovery) of certain regulatory assets, including Pine Street Barge Canal environmental site costs, and past demand side management program costs will begin January 2005 and will be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

POWER CONTRACT COMMITMENTS

Under an arrangement established on December 5, 1997 ("9701"), Hydro-Quebec paid \$8.0 million to the Company. In return for this payment, we provided Hydro-Quebec options for the purchase of power. Commencing April 1, 1998 and effective through 2015, the term of a previous contract with Hydro-Quebec (the "1987 Contract"), Hydro-Quebec may purchase up to 52,500 MWh ("option A") on an annual basis, at the 1987 Contract energy prices, which are substantially below current market prices. The cumulative amount of energy that may be purchased under option A shall not exceed 950,000 MWh. Over the same period, Hydro-Quebec may exercise an option to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy prices. Under option B, Hydro-Quebec may purchase no more than 200,000 MWh in any year. At September 30, 2003, the cumulative amount of power purchased by Hydro-Quebec under option B is approximately 513,000 MWh.

During the first nine months of 2003, \$3.5 million in power supply expense was recognized to reflect the net cost of option A and B, compared with \$2.3 million during the first nine months of 2002 for option A only. Hydro-Quebec had previously agreed not to call option B during the contract year ended October 31, 2002. The Company has purchased its estimated power supply requirements to cover the anticipated exercise of options A and B for 2004, and approximately half of its expected requirement for 2005 at unit prices slightly below unit prices paid during 2003.

Hydro-Quebec's option to curtail annual energy deliveries pursuant to a July 1994 Agreement can be exercised in addition to these purchase options if documented drought conditions exist. The exercise of this curtailment option is limited to five times, requiring notice four months in advance of any contract year, and cannot reduce deliveries by more than approximately 13 percent. The Company may defer the curtailment by one year. Hydro-Quebec also has the option to reduce the annual load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. Pursuant to the 1987 Contract, Hydro-Quebec reduced its load factor to 65 percent in 2003 and has notified the Company of its intention to reduce the load factor to 65 percent in 2004. The Company estimates that the net cost of Hydro-Quebec's exercise of its load factor reduction option will increase power supply expense during 2003 by approximately \$0.4 million.

It is possible our estimate of future power supply costs could differ materially from actual results.

4. SEGMENTS AND RELATED INFORMATION

The Company's electric utility operation is its only operating segment. The electric utility is engaged in the distribution and sale of electrical energy in the State of Vermont and also reports the results of its wholly owned

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unregulated subsidiaries (GMPG, GMRI, GMPIC and GMP Real Estate) and the rental water heater program as a separate line item in the Other Income section in the Consolidated Statement of Income.

NWR is an unregulated business that invested in energy generation, energy efficiency and wastewater treatment projects. As of September 30, 2003, most of NWR's net assets and liabilities have been sold or otherwise disposed. The remaining net liability reflects expected warranty obligations, net of equity investments in a wind farm and wastewater treatment projects.

5. DERIVATIVE INSTRUMENTS AND RISK MANAGEMENT

The Company records the annual cost of power obtained under long-term contracts as operating expenses. The Company meets the majority of its customer demand through a series of long-term physical and financial contracts. There are occasions when we may experience a short position for electricity needed to supply customers. During those periods, electricity is purchased at market prices.

SFAS 133 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 by SFAS 137, was effective for the Company beginning 2001.

One objective of the Company's risk management program is 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 contracts with counter-parties that have at least investment grade ratings. These transactions are used to mitigate the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures and authorization limits for transactions. Derivative financial instruments held by the Company are used as hedges or for cost control and not for trading.

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 application of SFAS 133. At September 30, 2003, the Company had a liability reflecting the net negative fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately \$16.8 million. The Company believes that the regulatory asset, determined using the Black's or Black-Scholes option valuation method, is probable of recovery in future rates. The regulatory liability is based on current estimates of future market prices that are likely to change by material amounts.

If a derivative instrument is terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss would be recognized in earnings immediately. For derivatives held to maturity, the earnings impact would be recorded in the period that the derivative is sold or matures.

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS") used to hedge against increases in fossil fuel prices. MS 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. The MS contract is a derivative under SFAS 133 and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this contract at September 30, 2003 is approximately \$5.3 million.

As described under "Power Contract Commitments", the 9701 arrangement grants Hydro-Quebec an option to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future

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net cost for this arrangement at September 30, 2003 is approximately \$22.1 million. We use futures contracts to hedge the 9701 call option.

6. 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 no legal retirement obligations associated with asset retirement obligations. Other non-legal removal costs related to utility plant, estimated at approximately \$20.4 million, are included in accumulated depreciation. The Company adopted SFAS No. 143 on January 1, 2003 as required. There was no cumulative effect of adopting SFAS No. 143.

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 was effective beginning with the three months ended June 30, 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 and amended disclosure provisions for stock-based compensation. The application of this accounting standard is not expected to materially impact the Company's financial position or results of operations.

In January 2003, the Financial Accounting Standards Board issued Interpretation 46, Consolidation of Variable Interest Entities. This standard will require an enterprise that is the primary beneficiary of a variable interest entity to consolidate that entity. The Interpretation must be applied to any existing interests in variable interest entities beginning in 2004. The Company does not expect to consolidate any existing interest in unconsolidated entities as a result of Interpretation 46.

In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("SFAS 149"). SFAS 149 amends Statement 133 for decisions made (1) as part of the Derivatives Implementation Group process that effectively required amendments to Statement 133, (2) in connection with other Board projects dealing with financial instruments, and (3) in connection with implementation issues raised in relation to the application of the definition of a derivative, in particular, the meaning of an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors, the meaning of underlying, and the characteristics of a derivative that contains financing components. Effective for contracts entered into or modified after June 30, 2003, we do not expect this statement to have a material effect on our financial position or results of operations.

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. Effective for financial instruments entered into or modified after May 31, 2003, we do not expect this statement to have a material effect on our financial position or results of operations.

7. COMPUTATION OF EARNINGS PER SHARE

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Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. The Company established a stock incentive plan for all directors and employees during the year ended December 31, 2000, and options granted are exercisable over vesting schedules of between one and four years.

	Three months ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
(in thousands)				
Net income before preferred dividends	\$3,041	\$3,046	\$8,227	\$8,372
Preferred stock dividend requirement	1	4	3	99
	-----	-----	-----	-----
Net income applicable to common stock	\$3,040	\$3,042	\$8,224	\$8,273
	=====	=====	=====	=====
Weighted average number of common shares-basic.	4,982	5,723	4,970	5,709
Dilutive effect of stock options	159	156	160	166
Anti-dilutive stock options	-	-	-	-
	-----	-----	-----	-----
Weighted average number of common shares-diluted.	5,141	5,879	5,130	5,875
	=====	=====	=====	=====

GREEN MOUNTAIN POWER CORPORATION
PART I-ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
SEPTEMBER 30, 2003

In this section, we explain the general financial condition and the results of operations for Green Mountain Power Corporation (the "Company") and its subsidiaries. This 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 year-to-date and what we expect they will be in the future;
- Where we expect to get cash for future capital expenditures; and
- How all of the above affects our overall financial condition.

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, and the defined benefit plan assumptions used to determine plan liabilities for our defined benefit retirement plans. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements.

As you read this section it may be helpful to refer to the consolidated financial statements and notes in Part I-Item 1.

There are statements in this section that contain projections or estimates and are considered to be "forward-looking" as defined by the Securities and Exchange Commission. In these statements, you may find words such as

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"believes," "estimates," "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 materially different from those projected. Some of the reasons the results may be different are listed below and are discussed under "Competition and Restructuring" in this section:

- Regulatory and judicial decisions or legislation;
- Weather;
- Energy supply and demand and pricing;
- Availability, terms, and use of capital;
- General economic and business risk;
- Nuclear and environmental issues;
- Changes in technology; and
- Industry restructuring and cost recovery (including stranded costs).

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

RESULTS OF OPERATIONS

EARNINGS SUMMARY - OVERVIEW

In this section, we discuss our earnings and the principal factors affecting them. We separately discuss earnings for the utility business and for our unregulated businesses.

	Total basic earnings per share of Common Stock			
	Three months ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
Utility business	\$0.59	\$0.51	\$1.59	\$1.40
Unregulated businesses .	0.02	0.02	0.06	0.05
	-----	-----	-----	-----
Earnings from:				
Continuing operations. .	0.61	0.53	1.65	1.45
Discontinued operations.	-	-	-	-
	-----	-----	-----	-----
Basic earnings per share	\$0.61	\$0.53	\$1.65	\$1.45
	=====	=====	=====	=====

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of \$0.59 in the quarter ended September 30, 2003, compared with utility earnings of \$0.51 per share in the third quarter of 2002. Earnings improved primarily due to decreased power supply costs and increased residential retail sales of electricity that more than offset decreased recognition of deferred revenues, higher administrative and general expenses and decreased earnings from our equity investment in Vermont Yankee.

Basic earnings per share from utility operations for the nine months ended September 30, 2003 were \$1.59 compared with basic earnings per share of \$1.40 for the same period in 2002. Earnings improved primarily due to favorable weather conditions, resulting in increased sales of electricity to residential customers and lower transmission expenses that were partially offset by higher administrative and general expenses and decreased earnings from our equity investment in Vermont Yankee.

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UNREGULATED BUSINESSES

Earnings from unregulated businesses, principally from the Company's water heater rental program, included in results from continuing operations for the three and nine months ended September 30, 2003 did not change materially when compared with the same periods in 2002. A financial summary for these businesses follows:

	Three Months Ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
(In thousands)				
Revenue	\$ 247	\$ 326	\$ 744	\$ 828
Expense	144	218	426	535
	-----	-----	-----	-----
Net Income . .	\$ 103	\$ 108	\$ 318	\$ 293
	=====	=====	=====	=====

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatt hour ("MWh") sales and average number of customers for the three and nine months ended September 30, 2003 and 2002 are summarized below:

	Three months ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----
(dollars in thousands)				
Operating revenues				
Retail	\$ 50,287	\$ 51,053	\$ 148,659	\$ 151,798
Sales for Resale . . .	20,952	21,588	58,593	53,489
Other	736	836	2,123	2,191
	-----	-----	-----	-----
Total Operating Revenues.	\$ 71,975	\$ 73,477	\$ 209,375	\$ 207,478
	=====	=====	=====	=====
MWh Sales-Retail	495,877	496,964	1,452,003	1,452,100
MWh Sales for Resale . . .	622,979	619,057	1,703,541	1,655,281
	-----	-----	-----	-----
Total MWh Sales	1,118,856	1,116,021	3,155,544	3,107,381
	=====	=====	=====	=====

Average Number of Customers

	Three months ended		Nine months ended	
	September 30		September 30	
	2003	2002	2003	2002
	-----	-----	-----	-----

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Residential	74,570	73,734	73,861	73,831
Commercial and Industrial	13,398	13,206	13,194	13,076
Other	65	67	65	65
	-----	-----	-----	-----
Total Number of Customers. .	88,033	87,007	87,120	86,972
	=====	=====	=====	=====

REVENUES

Total revenues from operations in the third quarter of 2003 decreased \$1.5 million or 2.0 percent compared with the same period in 2002, primarily as a result of a decrease of \$1.2 million in recognition of deferred revenues, a decrease of \$0.6 million in wholesale sales, and a decrease of approximately \$0.3 million in commercial and industrial revenues, partially offset by a \$0.7 million increase in residential revenues. The increase in residential revenues had a significant impact on earnings and resulted principally from warmer than normal summer temperatures.

Retail operating revenues reflected a \$1.2 million decline in the recognition of deferred revenues during the third quarter of 2003, compared with the same quarter of 2002. Revenues were deferred during 2001 in accordance with the settlement of the Company's retail rate case approved by the Vermont Public Service Board (the "VPSB") in January 2001 (the "Settlement Order"). The Settlement Order resulted in the elimination of seasonal rates, generating an additional \$8.5 million in cash flow in 2001. The Settlement Order provided that recognition of this additional \$8.5 million of revenue be deferred and then recognized to offset increased costs during 2001, 2002, or 2003. As of September 30, 2003, the Company has \$4.1 million in remaining unrecognized deferred revenues, which will be used to offset increased costs or write off regulatory assets during 2003 or 2004. See Notes-2003 Proposed Rate Plan for further details.

Total retail MWh sales of electricity in the third quarter of 2003 decreased 0.2 percent from the same quarter of 2002, primarily as a result of a decrease in sales of 2.5 percent and 1.2 percent, respectively, to commercial and industrial customers, substantially offset by an increase in residential sales of 4.7 percent

The Company's major industrial customer, International Business Machines ("IBM"), accounted for 17.3% of retail sales revenue in 2002. The Company currently estimates, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to eight percent, inclusive of projected related declines in sales to residential and commercial customers.

We sell wholesale electricity to others for resale. Our revenue from wholesale MWh sales of electricity decreased approximately \$0.6 million or 3.0 percent in the third quarter of 2003 compared with the same period in 2002. The decrease was due primarily to reductions in sales to MS.

Total operating revenues for the nine months ended September 30, 2003, compared with the same period during 2002, increased by \$1.9 million, primarily due to increased wholesale sales and increased residential revenues, partially offset by decreased deferred revenue recognition. Retail operating revenues reflected a \$5.5 million decline in the recognition of deferred revenues during the first nine months of 2003, compared with the same period of 2002, partially offset by an increase of \$3.1 million or 5.7 percent in residential revenues during the same comparative period. Strong operating results during the first nine months of the year reduce the likelihood that deferred revenue recognition will be needed to achieve the allowed return on equity of 10.5 percent in 2003 contemplated in the Company's July 11, 2003 Memorandum of Understanding with the Vermont Department of Public Service. If the VPSB declines to approve the Memorandum of Understanding in 2003, then the Company may recognize or defer additional deferred revenues sufficient to achieve a return on equity of 11.25 percent, the Company's allowed return in the absence of approval of the Memorandum.

Total retail MWh sales of electricity in the first nine months of 2003

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increased 0.2 percent from the same period of 2002, primarily as a result of increased residential sales of 6.4 percent, a decrease in commercial sales of 1.2 percent and a decline in industrial sales of 3.6 percent. The decrease in industrial sales arose primarily from reduced snowmaking. These sales have an immaterial impact on operating results because snowmaking sales are subject to a dispatchable rate tariff arrangement that significantly reduces the Company's margin on such sales.

Wholesale revenues increased \$5.1 million or 9.5 percent during the first nine months of 2003, compared with the same period in 2002, as a result of rescheduled power supply deliveries and higher market prices. Wholesale revenues typically have an insignificant impact on earnings because market wholesale prices usually approximate our marginal costs for energy, but the first quarter was an exception. One of the Company's principal energy suppliers reduces energy deliveries in the event of system limitations. These delivery deficiencies are typically scheduled at a later time by the Company. During the first quarter of 2003, the Company scheduled approximately 35,000 MWh of energy from this supplier to make up for delivery deficiencies in earlier periods, and sold that energy on the market at unusually high market energy prices. Market energy prices were higher than normal in the first quarter as a result of the Venezuelan oil strike, colder than normal temperatures across the U.S and the threat of war.

OPERATING EXPENSES

POWER SUPPLY EXPENSES

Power supply expenses decreased \$2.9 million or 5.4 percent in the third quarter of 2003 compared with the same period in 2002, as a result of a \$1.9 million decline in costs under the Company's power supply contract with MS, and decreased costs of power from Vermont Yankee.

Power supply expenses at Vermont Yankee decreased \$1.4 million or 13.2 percent during the third quarter of 2003 compared with the same period of 2002, primarily due to \$1.0 million amortization of past outage costs recorded during the third quarter of 2002. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies".

Company-owned generation expenses decreased \$270,000 or 14.6 percent in the third quarter of 2003 compared with the same period in 2002, primarily due to decreased production.

The cost of power that we purchased from other companies decreased \$1.2 million or 3.0 percent in the third quarter of 2003 compared with the same period in 2002, primarily due to a \$1.9 million decrease in cost of power purchased from MS, and a \$0.6 million decrease in wholesale sales of electricity. These decreases were partially offset by higher prices paid for other power supply resources. See the discussion under Part I, Item 1, Note 3 "Commitments and Contingencies-Power Contract Commitments" for more detail regarding the 9701 arrangement, and Part I, Item 1, Note 5, "Derivative Instruments and Risk Management" for further information regarding the MS contract.

During the third quarter of 2003, \$1.0 million in power supply expense was recognized to reflect the costs associated with the Company's 9701 arrangement with Hydro-Quebec. During the third quarter of 2002, \$0.8 million in power supply expense was recognized to reflect such costs, which were lower in 2002 as a result of Hydro-Quebec's agreement not to exercise a portion of its call options during the 2002 contract year. The cumulative amount of power purchased or called to date by Hydro-Quebec under option B is approximately 513,000 MWh, out of a total of 600,000 MWh which may be called over the life of the arrangement. Hydro-Quebec exercised its option to call approximately 107,000 MWh under 9701 for July and August 2003. The Company previously purchased energy in anticipation of Hydro-Quebec's call.

Both the 9701 arrangement and any related forward purchase contracts are considered derivative instruments as defined by SFAS 133. On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effect relating to

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future periods caused by application of SFAS 133, and as a result, we do not anticipate SFAS 133 to affect earnings. The current costs of both the 9701 arrangement and other forward purchase arrangements, including our MS contract, are being fully recovered in our retail rates. At September 30, 2003, the Company had a regulatory asset of approximately \$16.8 million related to derivatives that the Company believes is probable of recovery. The regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

Power supply expenses decreased \$316,000 or 02 percent in the first nine months of 2003 compared with the same period in 2002, as a result of a \$6.1 million decline in costs under the Company's power supply contract with MS, offset in part by increases arising from increased wholesale sales of \$5.1 million and an increase of \$1.2 million in power supply expense under the 9701 arrangement with Hydro-Quebec.

Power supply expense at Vermont Yankee increased \$1.6 million or 6.0 percent during the first nine months of 2003 compared with the same period of 2002, primarily due to an increase in energy provided under the Power Purchase Agreement between VY and Entergy. An outage in the second quarter of 2002 reduced energy provided from the Vermont Yankee nuclear power plant. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies". Company-owned generation expense increased \$2.6 million or 77.0 percent in the first nine months of 2003 compared with the same period in 2002, primarily due to increases in fuel costs used to operate the Company's owned peak generation facilities and increased output and fuel costs at the Stony Brook generating facility in which we have an 8.8 percent joint ownership interest.

The cost of power that we purchased from other companies decreased \$7.4 million or 6.4 percent in the first nine months of 2003 compared with the same period in 2002, primarily due to a \$6.1 million decrease in the cost of power purchased from MS. During the first nine months of 2003, \$3.5 million in power supply expense was recognized to reflect the costs of the 9701 arrangement, compared with \$2.3 million during the first nine months of 2002.

OTHER OPERATING EXPENSES

Other operating expenses increased \$1.4 million or 43.9 percent in the third quarter of 2003 compared with the same period in 2002, as a result of increases in employee benefit plan costs and costs related to governance matters, and adjustments to deferred charges. Other operating expenses increased \$2.6 million or 25.1 percent in the first nine months of 2003 compared with the same period in 2002 for the same reasons.

TRANSMISSION EXPENSES

Transmission expenses decreased by approximately \$291,000 or 7.8 percent for the three months ended September 30, 2003 compared with the same period in 2002, due to a reduction in the amount of pool transmission expense allocated from the rest of New England as a result of changes in cost allocation methods used by ISO New England.

Transmission expenses decreased by approximately \$716,000 or 6.1 percent for the nine months ended September 30, 2003 compared with the same period in 2002, for the same reasons.

During 2002, the Federal Energy Regulatory Commission ("FERC") accepted ISO New England's request to implement a standard market design ("SMD") governing wholesale energy sales in New England. ISO New England 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 pricing zone under the plan, although pricing may eventually be determined on a more localized ("nodal") basis. The Company does not expect the implementation of this SMD in its current form to have a material

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impact on the Company's power supply or transmission costs. The FERC has suggested that change to nodal pricing might be appropriate as early as 18 months after the implementation of SMD. Nodal pricing, if implemented, could have a material adverse impact on our power supply or transmission expense because certain nodes are expected to be congested absent future investments in transmission or generation assets.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking to amend its regulations and modify its existing pro forma open access transmission tariff to require that all public utilities with open access transmission tariffs modify their tariffs to reflect non-discriminatory, standardized transmission service and standard wholesale electric market design. This rulemaking, known as the "SMD NOPR," proposes to implement standard market design and locational marginal pricing in all regions of the United States, including New England. The SMD NOPR is currently in the rulemaking comment period. It is uncertain whether or how implementation of FERC's SMD NOPR, if and when approved, may differ from the ISO New England SMD plan, or how implementation of the SMD NOPR could impact the Company's power supply or transmission costs, although the impacts could be material.

Under SMD, the zone experiencing the voltage support problems will pay for costs of local generation used to maintain voltage support for reliability. Previously, these costs would have been allocated throughout New England. VELCO owns certain transmission equipment on a primary transmission line ("PV20 line") supporting northwestern Vermont. This equipment requires repair and will likely be unavailable until next summer. We are unable to estimate whether, or to what degree, VELCO will need to utilize additional generation to replace voltage support previously provided by the PV20 line. If additional generation were required, our share of these costs would be material.

VELCO 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. The proposed Northwest Reliability Project must be approved by the VPSB. If approved, the project is estimated to cost approximately \$128 million and is expected to be in service by December 2007. Under current NEPOOL rules, qualifying large transmission project costs are shared among all New England utilities as "pooled transmission facilities" ("PTF"), with Vermont utilities responsible for approximately five percent of such regionalized costs. NEPOOL has approved the principal cost components of the Northwest Reliability Project for inclusion as PTF.

On October 31, 2003, ISO New England filed with the FERC a proposal to approve a Regional Transmission Organization ("RTO") for New England. This RTO filing preserves the cost-sharing principles applicable to facilities approved as PTF under NEPOOL rules, including the Northwest Reliability Project. ISO New England's filing is subject to approval by FERC.

MAINTENANCE EXPENSES

Maintenance expenses decreased \$97,000 or 4.7 percent for the three months ended September 30, 2003 compared with the same period in 2002, primarily due to a decrease in scheduled maintenance on distribution facilities.

Maintenance expenses decreased \$344,000 or 5.4 percent for the nine months ended September 30, 2003 compared with the same period in 2002, for the same reasons.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses for the quarter ended September 30, 2003 decreased \$205,000 or 5.7 percent compared with the same period in 2002, reflecting a decrease in the amortization of demand side management assets.

Depreciation and amortization expenses for the nine months ended September 30, 2003 decreased \$193,000 or 1.8 percent compared with the same period in 2002, for the same reasons as the quarterly decrease.

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TAXES OTHER THAN INCOME TAXES

Other tax expense for the third quarter and first nine months of 2003 decreased by \$104,000 and \$51,000, respectively, compared with the same periods in 2002 due to reductions in property taxes.

INCOME TAXES

Income taxes increased \$32,000 or 1.8 percent in the third quarter of 2003 compared with the same period in 2002 due to an increase in pretax book income from operations.

Income taxes decreased \$67,000 or 1.4 percent in the first nine months of 2003 compared with the same period in 2002 due to a decrease in pretax book income.

OTHER INCOME

Other income decreased \$308,000 or 38.4 percent during the three months ended September 30, 2003 compared with the same period in 2002, as earnings from VY decreased due to the sale of the nuclear power plant to Entergy in 2002. See Note 2, Investment in Associated Companies, for further information.

Other income decreased by \$352,000 or 18.1 percent in first nine months of 2003 compared with the same period in 2002, for the same reason.

INTEREST CHARGES

Interest charges increased \$254,000 or 16.9 percent in the third quarter of 2003 compared with the same period in 2002, due to increases in long-term debt balances arising from the issuance of \$42.0 million of first mortgage bonds in December 2002.

Interest charges increased \$752,000 or 16.5 percent in the first nine months of 2003 compared with the same period in 2002, for the same reason.

PREFERRED STOCK DIVIDENDS

Dividends paid on preferred stock decreased \$3,000 for the quarter ended September 30, 2003 compared with the same period in 2002, due to redemptions of preferred stock during 2002 as discussed in this section under "Liquidity and Capital Resources".

Dividends paid on preferred stock decreased \$96,000 for the first nine months 2003 compared with the same period in 2002, for the same reason.

LIQUIDITY AND CAPITAL RESOURCES

In the nine months ended September 30, 2003, we spent \$14.5 million principally for expansion and improvements of our transmission, distribution and generation plant, and environmental expenditures. We expect to spend approximately \$7.9 million during the remainder of 2003, principally for improvements to transmission, distribution and generation plant, and environmental expenditures.

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 \$1.5 million outstanding on the Fleet-Sovereign Agreement at September 30, 2003, with an interest rate of 4.0 percent. The Fleet-Sovereign Agreement expires June 16, 2004. There was no non-utility short-term debt outstanding at September 30, 2003.

The annual dividend was \$0.60 per share for the year ended December 31, 2002. The Settlement Order had limited the annual dividend rate at its then current level of \$0.55 per share until our short-term credit facilities were replaced with long-term debt or equity financing. The Company used proceeds of a \$42 million long-term debt issue in December 2002 to replace all short-term borrowings, satisfying the conditions in the Settlement Order and permitting the Company to raise its dividend. The annualized dividend rate was increased from \$0.55 per share to \$0.76 per share beginning with the \$0.19 quarterly dividend declared in December 2002. The Company intends to increase the dividend in a measured consistent manner until the payout ratio falls between 50 percent and

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70 percent of anticipated earnings. The current dividend payout ration is approximately 40 percent. The Company believes this payout ratio to be consistent with that of other utilities having similar risk profiles.

The Company completed a capital restructuring plan that reduced equity and high-priced debt during 2002 and resulted in debt and equity ratios closer to its targets of 50 percent debt and 50 percent equity. Significant transactions resulting from the restructuring plan included:

On March 15, 2002, the Company redeemed \$5.1 million of the 10.0 percent first mortgage bonds due June 1, 2004;

During March and June 2002, the Company repurchased \$11.0 and \$1.0 million, respectively, of the 7.32 percent Class E preferred stock outstanding;

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; and

On December 16, 2002, the Company issued \$42 million principal amount of first mortgage bonds bearing interest at 6.04 percent per year and maturing on December 1, 2017.

The credit ratings of the Company's securities at September 30, 2003 were:

	Fitch -----	Moody's -----	Standard & Poor's -----
First mortgage bonds	BBB+	Baa1	BBB
Preferred stock. . .	BBB	Ba1	BB

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

Moody's affirmed the Company's senior secured debt rating at Baal, 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 MS 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
FUTURE OUTLOOK-COMPETITION AND RESTRUCTURING-The electric utility business continues to experience rapid and substantial changes. These changes are the result of the following trends:

disparity in electric rates, transmission, and generating capacity among and within various regions of the country;
improvements in generation efficiency;
increasing demand for customer choice;
consolidation through business combinations;
new regulations and legislation intended to foster competition, also known as restructuring;
changes in rules governing wholesale electricity markets; and
increasing volatility of wholesale market prices for electricity.

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Power supply difficulties in some regulatory jurisdictions, such as California, and proposed changes in regional and national wholesale markets appear to have dampened any immediate push towards de-regulation in Vermont. We are unable to predict what form future restructuring legislation, if adopted, will take and what impact that might have on the Company, but it could be material.

PENSION

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. The Company's pension plan assets are primarily made up of public equity and fixed income investments. 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 pension plan before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company adopted a plan and made pension plan contributions totaling \$3.5 million between September 1, 2002 and September 30, 2003. The Company intends to contribute up to an additional \$1.5 million by December 31, 2003. The Company's pension costs and cash funding requirements are expected to continue at an equivalent annual rate through 2004.

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, as prescribed by SFAS 87. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"), and did not affect net income for 2002. The charge to OCI may be restored through common equity in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

NEW ACCOUNTING STANDARDS

See Part I-Item 1, Note 6, "New Accounting Standards" for more information on the adoption of new accounting standards and the impact, if any, on the Company's financial position and operating results.

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 both 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.

MARKET RISK

Our material power supply contracts and arrangements are principally with Hydro Quebec, MS and Vermont Yankee. At September 30, 2003, more than 90 percent of our estimated load requirements through 2006 are expected to be met by these contracts and arrangements, and by our own generation and other power supply resources, which reduces the Company's exposure to market prices.

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Restructuring of the wholesale market for electricity has brought increased price volatility to our power supply markets. Inherent in our market risk sensitive instruments and positions are the potential losses that may result from adverse changes in commodity prices.

One objective of the Company's risk management program is to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by

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the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights with counter-parties that have at least investment grade ratings. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. The MS contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management's estimate of the fair value of the future net benefit of this arrangement at September 30, 2003 is approximately \$5.3 million. Assumptions used to calculate the future net benefit using the Blacks option valuation model include a risk-free interest rate of 2.0 percent, volatility equivalent to a weighted average from NEPOOL, which varies from 32 percent in the first year to 27 percent in the fourth year, and locked in forward commitment prices for 2003, with an estimated forward market price of approximately \$43 per MWh for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Actual results may differ materially from the table below.

A sensitivity analysis has been prepared to estimate exposure to the market price risk of 9701, using the Black-Scholes model, over the next 13 years. Management's estimate of the fair value of the future net cost for this arrangement at September 30, 2003 is approximately \$22.1 million. Assumptions used within the model include a risk-free interest rate of 4.25 percent, volatility equivalent to the weighted average from NEPOOL, which varies from 48 percent in the first year to 27 percent in year 13, locked in forward commitment prices for 2003, and an average of approximately 60,000 MWh per year, with an estimated forward market price of \$59.81 per MWh during peak hours for periods beyond 2003. The forward price for electricity is consistent with the Company's current long-term wholesale energy price forecast. Quoted forward market prices for monthly peak power rates are not currently available beyond 2004. Actual results may differ materially from the table below.

The table below presents market risk estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in prices, which for the Company's derivatives discussed above totals approximately \$0.7 million. Actual results may differ materially from the table below. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are not recognized in earnings until the derivative positions are settled, and these costs are recovered in rates.

	Commodity Price Risk Fair Value		At September 30, 2003 Market Risk
	-----		-----
	(in thousands)		
Net short position	\$ 16,780	\$	709

ITEM 4. CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, the Company carried out an evaluation, with the participation of the Company's management, including the Company's President and Chief Executive Officer, and Controller and Treasurer, of the effectiveness of the Company's disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, the Company's President and Chief Executive Officer, and Controller and Treasurer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company (including its consolidated subsidiaries) required to be

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included in the Company's periodic SEC filings. There has been no change in the Company's internal control over financial reporting during the quarter ended September 30, 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

GREEN MOUNTAIN POWER CORPORATION

SEPTEMBER 30, 2003

PART II - OTHER INFORMATION

ITEM 1. Legal Proceedings

See Notes 3, 4 and 5 of Notes to Consolidated Financial Statements

ITEM 2. Changes in Securities

NONE

ITEM 3. Defaults Upon Senior Securities

NONE

ITEM 4. Submission of Matters to a Vote of Security Holders

NONE

ITEM 5. Other Information

NONE

ITEM 6.

(A) EXHIBITS

Exhibit 31.1 and Exhibit 31.2, Certification by Officers of Financial Information and Disclosure Controls and Procedures required by Section 302 of the Sarbanes-Oxley Act of 2002 accompanies this quarterly report.

Exhibit 32.1, Certification by Officers of Financial Information and Internal Controls required by Section 906 of the Sarbanes-Oxley Act of 2002 accompanies this quarterly report.

(B) REPORTS ON FORM 8-K

The following filings on Form 8-K were filed by the Company on the topics and dates indicated:

NONE

GREEN MOUNTAIN POWER CORPORATION

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the

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registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GREEN MOUNTAIN POWER CORPORATION

(Registrant)

Date: November 7, 2003

/s/ Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer
and President

Date: November 7, 2003

/s/ Robert J. Griffin

Officer)

Robert J. Griffin, (as Principal Financial
Vice President, Treasurer and Controller