GREEN MOUNTAIN POWER CORP
Form 10-Q
November 13, 2002

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, 2002

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 NOVEMBER 6, 2002
$3.33 1/3 PAR VALUE	5,729,240

PART I FINANCIAL INFORMATION
GREEN MOUNTAIN POWER CORPORATION
INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30,
2002 AND 2001

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		NINE MONTHS SEPTEMBER 3	
	2002	2001	2002	2
In thousands, except per share data				
OPERATING REVENUES	$73,477	$76,051	$207,478	$21
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation.	10,713	7,645	26,977	2
Company-owned generation.	1,847	1,625	3,425	

Purchases from others	40,622	45,495	116,356	12
Other operating	3,400	3,939	10,455	1
Transmission	3,707	3,431	11,679	1
Maintenance	2,082	1,739	6,356	
Depreciation and amortization	3,608	3,491	10,547	1
Taxes other than income	1,964	1,930	5,870	
Income taxes	1,789	2,183	4,813	
Total operating expenses	69,732	71,478	196,478	20
OPERATING INCOME	3,745	4,573	11,000	1
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations	1,362	553	2,430	
Allowance for equity funds used during construction	53	69	175	
Other income (deductions), net	(612)	90	(664)	
TOTAL OTHER INCOME (DEDUCTIONS)	803	712	1,941	
INCOME BEFORE INTEREST CHARGES	4,548	5,285	12,941	1
INTEREST CHARGES				
Long-term debt	1,253	1,491	3,866	
Other interest	272	215	780	
Allowance for borrowed funds used during construction	(23)	(43)	(77)	
TOTAL INTEREST CHARGES	1,502	1,663	4,569	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	3,046	3,622	8,372	
Preferred stock dividend requirement	4	235	99	
Income from continuing operations	3,042	3,387	8,273	
Loss on disposal, including provisions for operating losses during phaseout period	-	-	-	
NET INCOME APPLICABLE TO COMMON STOCK	$ 3,042	$ 3,387	$ 8,273	$
Common stock data				
Basic earnings per share	$ 0.53	$ 0.60	$ 1.45	$
Diluted earnings per share	0.52	0.58	1.41	
Cash dividends declared per share	$ 0.14	$ 0.14	$ 0.41	$
Weighted average common shares outstanding-basic	5,723	5,644	5,709	
Weighted average common shares outstanding-diluted	5,879	5,814	5,874	
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS				
Balance - beginning of period	$11,683	$ 4,602	$ 8,070	$
Net Income	3,046	3,622	8,372	
Preferred stock dividend requirement	(4)	(235)	(99)	
Other	50	-		
Cash Dividends-common stock	(788)	(777)	(2,356)	(
Balance - end of period	$13,987	$ 7,212	$ 13,987	$

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

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	UNAUDITED FOR THE NINE MONTHS ENDED SEPTEMBER 30 2002	2001
OPERATING ACTIVITIES:	In thousands	
Net income before preferred stock dividend requirement. . . .	$ 8,372	$ 9,739
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,547	10,803
Dividends from associated companies less equity income. . . .	(1,024)	267
Allowance for funds used during construction.	(253)	(274)
Amortization of purchased power costs	2,385	2,607
Deferred income taxes	3,068	(2,525)
Arbitration costs recovered	-	3,229
Deferred purchased power costs.	(1,982)	(5,254)
Accrued purchase power contract option call	-	(3,346)
Earnings cap deferral and rate levelization liability	(5,519)	9,663
Environmental and conservation amortization (deferrals), net.	(1,414)	(2,291)
Changes in:		
Accounts receivable	1,258	3,594
Accrued utility revenues.	964	1,335
Fuel, materials and supplies.	797	37
Prepayments and other current assets.	1,130	713
Accounts payable.	(636)	(3,786)
Accrued income taxes payable and receivable	1,458	3,428
Other current liabilities	(482)	1,073
Other	532	(1,100)
Net cash provided by continuing operations.	19,204	27,912
INVESTING ACTIVITIES:		
Construction expenditures	(14,127)	(9,212)
Investment in nonutility property	(134)	(146)
Net cash used in investing activities	(14,261)	(9,358)
FINANCING ACTIVITIES:		
Proceeds from term loan	.	12,000
Redemption of preferred stock	(12,325)	-
Issuance of common stock.	617	1,283
Reduction in long term debt	(5,100)	(1,700)
Power supply option obligation, net	-	160
Short-term debt, net.	11,000	(15,500)
Cash dividends and preferred stock dividend requirement . . .	(2,455)	(3,020)
Net cash used in financing activities	(8,264)	(6,777)
Net increase(decrease) in cash and cash equivalents	(3,321)	11,777
Cash and cash equivalents at beginning of period.	5,006	341
Cash and cash equivalents at end of period.	$ 1,685	$ 12,118

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for:		
Interest (net of amounts capitalized)	$ 4,738	$ 4,677
Income taxes, net	2,349	5,287

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

PART I, ITEM 1

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

	UNAUDITED AT SEPTEMBER 30, 2002	UNAUDITED AT SEPTEMBER 30, 2001	DECEMBER 31, 2001
In thousands			
ASSETS			
UTILITY PLANT			
Utility plant, at original cost	$308,830	$296,843	$302,489
Less accumulated depreciation	124,811	116,540	119,054
Net utility plant	184,019	180,303	183,435
Property under capital lease.	5,959	6,449	5,959
Construction work in progress	12,293	8,208	7,464
Total utility plant, net.	202,271	194,960	196,858
OTHER INVESTMENTS			
Associated companies, at equity	15,469	14,176	14,093
Other investments	7,235	6,725	6,852
Total other investments	22,704	20,901	20,945
CURRENT ASSETS			
Cash and cash equivalents	845	12,118	5,006
Accounts receivable, customers and others, less allowance for doubtful accounts of $613	15,853	18,771	17,111
Accrued utility revenues.	4,900	5,758	5,864
Fuel, materials and supplies, at average cost	3,261	4,019	4,058
Prepayments	925	1,635	1,976
Income tax receivable	-	-	1,699
Other	389	894	469
Total current assets.	26,173	43,195	36,183
DEFERRED CHARGES			
Demand side management programs	6,598	6,676	6,961
Purchased power costs	3,139	6,179	3,504
Pine Street Barge Canal	12,425	12,370	12,425
Power supply derivative deferral.	31,776	34,419	37,313
Other	13,829	14,697	14,870
Total deferred charges.	67,767	74,341	75,073

NON-UTILITY			
Other current assets.	8	8	8
Property and equipment.	250	251	250
Other assets.	739	822	817
Total non-utility assets.	997	1,081	1,075
TOTAL ASSETS.	$319,912	$334,478	$330,134

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	UNAUDITED AT SEPTEMBER 30, 2002	UNAUDITED AT SEPTEMBER 30, 2001	DECEMBER 31, 2001
In thousands except share data			
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION			
Common stock equity			
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,743,296, 5,656,048 and 5,701,010)	$ 19,145	$ 18,907	$ 19,004
Additional paid-in capital	75,057	74,306	74,581
Retained earnings.	13,987	7,212	8,070
Treasury stock, at cost (15,856 shares).	(428)	(378)	(378)
Total common stock equity.	107,761	100,047	101,277
Redeemable cumulative preferred stock.	85	12,560	12,325
Long-term debt, less current maturities.	59,000	82,400	74,400
Total capitalization	166,846	195,007	188,002
CAPITAL LEASE OBLIGATION	5,959	6,449	5,959
CURRENT LIABILITIES			
Current maturities of preferred stock.	150	235	235
Current maturities of long-term debt	8,000	9,700	9,700
Short-term debt.	23,000	-	-
Accounts payable, trade and accrued liabilities.	6,152	5,943	7,237
Accounts payable to associated companies	8,810	6,536	8,361
Accrued taxes.	1,032	-	-
Customer deposits.	822	832	971
Interest accrued	1,327	1,716	1,100
Rate Levelization liability.	3,008	8,613	8,527
Deferred revenues.	-	1,050	-
Other.	1,112	3,289	2,945
Total current liabilities.	53,413	37,914	39,076
DEFERRED CREDITS			
Power supply derivative liability.	32,616	34,419	37,313

Accumulated deferred income taxes.	27,040	23,331	23,759
Unamortized investment tax credits	3,201	3,483	3,413
Pine Street Barge Canal site cleanup	8,957	10,583	10,059
Other.	19,510	21,531	20,852
Total deferred credits	91,324	93,347	95,396
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Other Liabilities.	2,370	1,761	1,701
Total non-utility liabilities.	2,370	1,761	1,701
TOTAL CAPITALIZATION AND LIABILITIES	$319,912	$334,478	$330,134

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2002

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 period 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 2001 filed on Form 10-K, are adequate to make the information presented not misleading. The Vermont Public Service Board ("VPSB"), the regulatory commission in Vermont, sets the rates we charge our customers for their electricity. In 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. We estimate that $7.3 million will be used to offset increased costs during 2002, including $5.5 million that was recognized during the first three quarters. The remaining $1.2 million of deferred revenue is expected to be recognized in 2003.

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.

UNREGULATED OPERATIONS

We have or have had unregulated, wholly owned subsidiaries: Northern Water Resources, Inc. ("NWR"); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; and Green Mountain Resources, Inc. ("GMRI"). During 2000 and 2001, we sold most of the assets of NWR. See the disclosure under the caption "Segments and Related Information" for a more detailed discussion. We also have a rental water heater program that is not regulated by the VPSB. The results of the operations of these subsidiaries, including NWR during 2002, and the rental water heater program are included in equity in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Comparative Income Statements.

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	
	2002	2001	2002	2001
(in thousands)				
Gross Revenue.	$48,534	$37,868	$134,029	$135,863
Net Income Applicable. to Common Stock	5,911	1,641	8,860	4,765
Equity in Net Income .	1,111	296	1,682	560

On August 15, 2001, VY agreed to sell its nuclear power plant to Entergy Corporation for approximately $180 million. On July 31, 2002, Vermont Yankee announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy") had been completed. In addition to the sale of the generating plant, the transaction calls for Entergy 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 continues to own approximately 19 percent of the common stock of VY. Our benefits of the plant sale and power contract with Entergy include:

Vermont Yankee receives cash approximately equal to the book value of the plant assets, removing the potential for stranded costs associated with the plant.

Vermont Yankee and its owners will no longer bear operating risks associated with running the plant.

Vermont Yankee and its owners will no longer bear the risks associated with the eventual decommissioning of the plant.

Prices under the Power Purchase Agreement with 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 Vermont Yankee. Contract prices range from $49 to $55 for 2002, higher than the forecasted cost of continued ownership for the current year.

The PPA with Entergy 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.

Payments totaling $0.5 million were made to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale. Although the sale closed on July 31, 2002, the Company's distribution of the sale proceeds and final accounting for the sale are pending certain regulatory approvals and the resolution of certain closing items between the seller and purchaser. The Company expects its share of the Vermont Yankee sale proceeds to be distributed in 2003.

The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Entergy plant.

The VY plant had fuel rods that required repair during May 2002, a maintenance requirement that is not unique to VY. VY shutdown the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. The Company's 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's ownership share of VY has increased from approximately 17.9 percent last year to approximately 19.0 percent currently, due to VY's purchase of certain minority shareholders' interests. The Company's entitlement to energy produced by the VY nuclear plant has increased from approximately 18 percent to 20 percent of plant production through a series of transactions in connection with the sale of the plant to Entergy.

The increase in equity in earnings of VY resulted from VY's recognition of certain deferred tax assets as a result of the sale of the nuclear plant.

VERMONT ELECTRIC POWER COMPANY, INC. ("VELCO")
Percent ownership: 28.41% 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 the State and others using VELCO's transmission system.

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
(in thousands)				
Gross Revenue	$5,012	$6,806	$16,808	$22,524
Net Income.	261	230	774	782
Equity in Net Income.	70	75	239	221

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 are in substantial compliance 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, 2002, our total expenditures related to the Pine Street site since 1982 were approximately $26.4 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. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals 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 response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million 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". The VPSB Order released January 23, 2001 and discussed below did not change the status of Pine Street cost recovery.

RETAIL RATE CASE

The Company reached a final settlement agreement with the Department in its 1998 rate case during November 2000. The final settlement agreement 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 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 a 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. 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.

On January 23, 2001, the VPSB approved the Company's settlement (the "Settlement Order") 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; and
* The Company's further investment in non-utility operations is restricted.

In August 2002, the Company petitioned the VPSB for consent 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. On October 10, 2002, the VPSB issued an order approving the Company's request. Pursuant to this order, upon issuance of the new long-term debt and repayment of existing short and intermediate term indebtedness, the dividend freeze order will terminate, allowing the Company's Board of Directors to consider an increase in the Company's common stock dividend rate. The Company expects the Board of Directors to consider whether an increase in the dividend level would be appropriate at its December 2002 meeting.

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.

During the first nine months of 2002, $2.3 million in power supply expense was recognized to reflect the cost of option A, which is recognized ratably over the year. Hydro-Quebec has previously agreed not to call option B during the 2002 contract year. At September 30, 2002, the cumulative amount of power purchased by Hydro-Quebec under option B is approximately 458,000 MWh.

During the first quarter of 2001, Hydro-Quebec exercised option A and option B, calling for deliveries of 134,592 MWh during June, July and August of 2001. The Company recognized $6.0 million in expense during the nine months ended September 30, 2001 to reflect 9701 estimated costs. A regulatory asset of $1.6 million was established for the remaining estimated difference between the option exercise price and the expected cost of replacement power for 2001.

If estimated costs of fulfilling the Hydro-Quebec option calls exceed amounts recovered in rates, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first nine months of 2002 and 2001. No charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2002.

Hydro-Quebec's option to curtail 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 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 the load factor reduction by one year under the same contract. During 2001, Hydro-Quebec exercised the first of its load factor reduction options intended for 2002, and the Company delayed the effective date of this exercise until 2003. 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.

COMPETITION

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. In March 2002, voters in Rockingham authorized Rockingham to create a municipal utility by acquiring a municipal plant, which would include the Bellows Falls hydroelectric facility and the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. 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 our remaining customers do not subsidize a Rockingham municipal utility.

4. SEGMENTS AND RELATED INFORMATION

The Company operated one segment during 2002, the electric utility operations. 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 unregulated subsidiaries (GMPG, GMRI, NWR 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, 2002, 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 two wind farms and wastewater treatment projects.

5. DERIVATIVE INSTRUMENTS AND RISK MANAGEMENT

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended ("SFAS 133").

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 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. Futures, swaps and forward contracts are used to hedge market prices should option calls by Hydro-Quebec be considered probable of exercise. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings effects relating to future periods caused by application of SFAS 133. At September 30, 2002, the Company had a liability reflecting the fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately $32.6 million. The Company believes that the regulatory asset is probable of recovery in future rates. The liability is based on current estimates of future market prices that are subject 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 was scheduled to expire on December 31, 2003. In August 2002, the Company extended the contract with MS through December 31, 2006. Beginning in 2004, the extended contract includes only our interests in the Wyman and StonyBrook plants with respective capacities of 7 MW and 45 MW, and our estimated load requirements not satisfied by contractual arrangements and other owned generation. The cost of power purchased from MS for 2003 is expected to be approximately $7.9 million less than the cost of power purchased from MS during 2002. The remainder of our load requirements are substantially provided through our power supply contracts and arrangements with Hydro-Quebec, our entitlements to power generated at the Vermont Yankee nuclear plant now owned by Entergy, and Company-owned generation. Management's estimate of the fair value of the future net cost of this contract at September 30, 2002 is approximately $5.2 million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments. We currently have an arrangement with Hydro-Quebec that grants it 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 net cost for this arrangement at September 30, 2002 is approximately $27.4 million.

6. NEW ACCOUNTING STANDARDS

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 141, Business Combinations ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142"). SFAS 141 requires the use of the purchase method to account for business combinations initiated after June 30, 2001 and uses a non-amortization approach to purchased goodwill and other indefinite-lived intangible assets. Under SFAS 142, effective for fiscal years beginning after December 15, 2001, goodwill and intangible assets deemed to have indefinite lives, will no longer be amortized, and will be subject to annual impairment tests. The adoption of these accounting standards did not impact the Company's financial position or results of operations as of September 30, 2002.

In 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), effective for the Company's 2003 fiscal year. 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 not yet determined what impact, if any, the accounting standard will have on its financial position or results of operations.

In 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), effective for fiscal years beginning after December 15, 2001. SFAS 144 specifies accounting and reporting for the impairment or disposal of long-lived assets. The adoption of SFAS 144 did not impact the Company's financial position or results of operations as of September 30, 2002.

7. COMPUTATION OF EARNINGS PER SHARE

Earnings per share are based on the weighted average number of common and common stock equivalent shares outstanding during each year. The Company established 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 September 30		Nine months ended September 30	
	2002	2001	2002	2001
(in thousands)				
Net income before preferred dividends. .	$3,046	$3,622	$8,372	$9,739
Preferred stock dividend requirement . .	4	235	99	704
Net income applicable to common stock. .	$3,042	$3,387	$8,273	$9,035

Average number of common shares-basic. .	5,723	5,644	5,709	5,615
Dilutive effect of stock options	156	170	166	162
Anti-dilutive stock options.	-	-	-	-
Average number of common shares-diluted.	5,879	5,814	5,875	5,777

GREEN MOUNTAIN POWER CORPORATION
PART I-ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
SEPTEMBER 30, 2002

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 regulatory accounting framework within which we operate, the method by which we recognized deferred revenues, the expected returns selected for our defined benefit retirement plans, the probability assigned by management for recovery of our regulatory assets, and the manner in which we account for certain power supply arrangements that qualify as derivatives. These accounting policies, among others, affect the Company's significant judgments and estimates used in the preparation of its consolidated financial statements, including estimates and judgments used in determining the current period recognition of revenues deferred in 2001, as discussed further under the caption "Operating Revenues and MWh Sales-Revenues, in this section.

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 "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 September 30		Nine months ended September 30	
	2002	2001	2002	2001
Utility business	$0.51	$0.58	$1.40	$ 1.57
Unregulated businesses .	0.02	0.02	0.05	0.07
Earnings from:				
Continuing operations. .	0.53	0.60	1.45	1.64
Discontinued operations.	-	-	-	(0.03)
Basic earnings per share	$0.53	$0.60	$1.45	$ 1.61

*The three and nine months ended September 30, 2002 include recognition of $1.2 million and $5.5 million of deferred revenues, respectively.

*The three and nine months ended September 30, 2002 include recognition of $1.2 million and $5.5 million of deferred revenues, respectively.

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of $0.51 in the quarter ended September 30, 2002, compared with utility earnings of $0.58 per share in the third quarter of 2001. Earnings declined in the third quarter of 2002 as a result of increased power supply costs to serve retail sales. These additional costs were partially offset by increased retail revenues and income recognized as a result of the sale of the Vermont Yankee ("VY") nuclear power plant.

Retail operating revenues increased by $1.7 million during the third quarter of 2002, compared with the same quarter of 2001, primarily due to the recognition of $1.2 million in revenues 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 revenue be deferred and then recognized to offset increased costs during 2001, 2002, or 2003. Management expects the Settlement Order to provide the Company a better opportunity to earn its allowed rate of return for these time periods.

Basic earnings per share from utility operations for the nine months ended September 30, 2002 were $1.40 compared with basic earnings per share of $1.57 for the same period in 2001, due to the same factors influencing third quarter results.

UNREGULATED BUSINESSES

Earnings from unregulated businesses included in results from continuing operations for the three months ended September 30, 2002 were slightly lower than during the same period in 2001. A financial summary for these businesses follows:

In thousands	Three Months Ended September 30 2002	Three Months Ended September 30 2001	Nine Months Ended September 30 2002	Nine Months Ended September 30 2001
Revenue. . .	$ 326	$ 251	$ 828	$ 761
Expense. . .	218	139	$ 535	395
Net Income .	$ 108	$ 112	$ 293	$ 366

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatthour ("MWh") sales and average number of customers for the three and nine months ended September 30, 2002 and 2001 are summarized below:

(dollars in thousands)	Three months ended September 30 2002	Three months ended September 30 2001	Nine months ended September 30 2002	Nine months ended September 30 2001
Operating revenues				
Retail.	$ 51,053	$ 49,009	$ 151,798	$ 146,548
Sales for Resale. . .	21,588	25,579	53,489	68,177
Other	836	1,463	2,191	3,594
Total Operating Revenues.	$ 73,477	$ 76,051	$ 207,478	$ 218,319
MWh sales-Retail.	496,964	499,671	1,448,326	1,479,586
MWh sales for Resale. . .	619,057	673,868	1,655,281	1,857,252
Total MWh Sales	1,116,021	1,173,539	3,103,607	3,336,838

Average Number of Customers

	Three months ended September 30 2002	Three months ended September 30 2001	Nine months ended September 30 2002	Nine months ended September 30 2001
Residential	73,734	73,213	73,740	73,146
Commercial and Industrial	13,206	13,033	13,140	12,988

Other	67	65	65	65
Total Number of Customers. .	87,007	86,311	86,945	86,199

REVENUES

Total revenues from operations in the third quarter of 2002 decreased $2.6 million or 3.4 percent compared with the same period in 2001, primarily as a result of a decrease of $4.0 million in revenues from wholesale sales of electricity, offset in part by a $2.0 million increase in retail revenues. While operating revenues result from retail and wholesale sales of electricity, substantially all of the Company's profits arise from retail sales.

Retail revenues in the third quarter of 2002 were $2.0 million or 4.1 percent higher compared with the same period in 2001, primarily as a result of the recognition of $1.2 million of revenues deferred during 2001 under the Settlement Order.

Total retail MWh sales of electricity in the third quarter of 2002 decreased by 0.5 percent from the same quarter of 2001, reflecting a decrease in sales to industrial customers of 3.8 percent that was partially offset by increased sales of 0.3 percent to small commercial and industrial customers and 2.8 percent to residential customers. Other operating revenue decreased $0.6 million in the third quarter of 2002 compared with the same period of 2001, primarily due to $0.4 million in settlement proceeds received in 2001, arising from our partial ownership of the W.F. Wyman oil-fired generating unit.

The Company's major industrial customer, International Business Machines ("IBM"), accounting for 19.2% of retail sales revenue in 2001, has reduced its Vermont workforce by 1,500 this year, to a level of approximately 7,000 employees. Company sales of electricity to IBM for the nine months ended September 30, 2002 declined by approximately four percent compared to sales for the same period of the prior year, and are primarily responsible for the decline in Company sales to industrial customers. If future significant losses in electricity sales to IBM were to occur, the Company's earnings could be impacted adversely. If earnings were materially reduced as a result of lower retail sales, the Company would seek a retail rate increase from the VPSB.

Retail revenues for the nine months ended September 30, 2002 were $5.3 million or 3.6 percent higher when compared with the same period in 2001, reflecting the recognition of $5.5 million of deferred revenues, partially offset by decreased retail MWh sales of approximately 2.1 percent due to warmer than normal winter temperatures and a softening economy in 2002.

The Company currently estimates that its earnings for 2002 will approximate its allowed rate of return of 11.25% percent, and that in 2002 it will recognize approximately $7.3 million of revenues deferred under the Settlement Order during 2001. The Company also expects that in 2003 it will recognize the remaining $1.2 million of revenues deferred under the Settlement Order.

We sell wholesale electricity to others for resale. Our revenue from wholesale MWh sales of electricity decreased approximately $4.0 million or 15.6 percent in the third quarter of 2002 compared with the same period in 2001. The decrease was due primarily to decreased sales under various arrangements with Hydro-Quebec. Revenue from wholesale MWh sales for the nine months ended September 30, 2002 decreased $14.7 million or 21.5 percent when compared with the same period in 2001 due to decreased sales under arrangements with Hydro-Quebec and Morgan Stanley Capital Group, Inc. ("MS").

OPERATING EXPENSES

POWER SUPPLY EXPENSES

Power supply expenses decreased 2.9 percent or $1.6 million in the third quarter of 2002 when compared with the same period in 2001, as a result of a decrease of $4.0 million of wholesale sales of electricity and reduced costs under a 1997 arrangement with Hydro-Quebec (the "9701 arrangement", or "9701"), offset in part by a $1.4 million increase in the cost of power under our contract with MS and an approximate $2.3 million net increase in the costs of power that we purchase from VY.

Power supply expenses at Vermont Yankee increased 40.1 percent or $3.1 million during the third quarter of 2002 compared with the third quarter of 2001, primarily due to an increase in energy costs under the Power Purchase Agreement between VY and Entergy (the "PPA"), offset in part by an increase of approximately 20,000 MWh in the Company's entitlement to power generated at the Entergy nuclear plant in the third quarter of 2002. The Company estimates that its net increase in total power supply costs arising from VY's sale of its nuclear plant to Entergy to be approximately $2.3 million, after accounting for the value of the Company's added entitlement to VY power in the third quarter of 2002, when compared with the same period in 2001. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies".

Company-owned generation expenses increased $0.2 million in the third quarter of 2002 compared with the same period in 2001, primarily due to increased output and fuel costs at the Stony Brook generating facility in which the Company has a 8.8 percent joint ownership interest.

The cost of power that we purchased from other companies decreased 10.7 percent or $4.9 million in the third quarter of 2002 compared with the same period in 2001, primarily due to a $4.0 million reduction of wholesale sales of electricity revenues, and decreased expenses under the 9701 arrangement with Hydro-Quebec, pursuant to which Hydro-Quebec has the right to purchase electricity from the Company at rates below current market prices. These decreases were partially offset by higher power supply costs of $1.4 million under the MS contract. 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, including the recent renegotiation of the MS contract.

The 9701 arrangement allows Hydro-Quebec to exercise an option to purchase power from the Company at energy prices based on a 1987 contract, and below current market prices. During the third quarter of 2002, $0.8 million in power supply expense was recognized to reflect the costs of option A, which are recognized ratably over the year. During the third quarter of 2001, $1.6 million in power supply expense was recognized to reflect the costs of options A and B. Hydro-Quebec has previously agreed not to call option B during the 2002 contract year. The cumulative amount of power purchased to date by Hydro-Quebec under option B is approximately 458,000 MWh out of a total of 600,000 MWh which may be called over the life of the of the arrangement.

Power supply expenses for the first nine months of 2002 decreased 5.3 percent or $8.2 million compared with the same period in 2001, primarily due to a reduction in wholesale sales of electricity and lower retail sales of electricity, offset in part by increased expense under our contract with MS and increased costs of power we purchased from VY.

Power supply expense at Vermont Yankee increased $5.5 million or 25.4 percent for the first nine months of 2002 compared with the same period in 2001, primarily due to increased energy costs under the PPA between VY and Entergy during 2002, and due to the deferred maintenance and repair costs associated with a scheduled refueling outage in 2001. Vermont Yankee scheduled outage costs were deferred and amortized over an eighteen-month refueling cycle.

Company-owned generation expenses decreased $0.4 million or 11.5 percent in the first nine months of 2002 compared with the same period in 2001, primarily due to lower fuel costs and reduced need to run peak generation facilities for system reliability.

Purchased power expense decreased $13.2 million or 10.2 percent in the first nine months of 2002 compared with the first nine months of 2001, primarily due to decreased wholesale electric sales, decreased expenses under the 9701 arrangement with Hydro-Quebec and reductions in retail MWh sales of electricity, which were in part offset by higher power supply costs under both the MS and small power producer contracts

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 allows the Company to defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133, and as a result, we do not anticipate SFAS 133 to cause earnings volatility. At September 30, 2002, the Company had a regulatory asset of approximately $32.6 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.

The cost of power purchased from MS for 2003 is expected to be approximately $7.9 million less than the cost of power purchased from MS during 2002, due primarily to reductions in energy prices under the renegotiated MS contract. The remainder of our load requirements are substantially provided through our power supply contracts and arrangements with Hydro-Quebec and our entitlements to power generated at the Vermont Yankee nuclear plant now owned by Entergy.

OTHER OPERATING EXPENSES

Other operating expenses decreased 13.7 percent or $0.5 million in the third quarter of 2002 compared with the same period in 2001, as a result of reductions in consulting costs and decreases in pole treatment costs.

Other operating expenses decreased 10.7 percent or $1.3 million in the first nine months of 2002 compared with the same period in 2001 primarily due to reductions in consulting costs in 2002, while 2001 included expenses of hiring replacement workers during a union strike in January 2001.

TRANSMISSION EXPENSES

Transmission expenses increased by approximately $0.3 million or 8.1% for the three months ended September 30, 2002, compared with the same period in 2001. The Company's relative share of transmission costs varies with the peak demand recorded on Vermont's transmission system. The Company's share of those costs has increased due to its increased load growth, relative to other Vermont utilities, experienced during the previous twelve months, and also because of increased transmission investment by VELCO, and increased congestion charges. Transmission expenses increased by approximately $1.2 million or 10.7 percent for the nine months ended September 30, 2002, compared with the same period in 2001 for the same reasons mentioned in the three-month comparison. Congestion charges recorded in the first nine months of 2002 and 2001 reflect the lack of adequate transmission or generation capacity in certain locations within New England, and these charges are allocated to all ISO New England members.

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 to modify these tariffs to reflect non-discriminatory, standardized transmission service and standard wholesale electric market design ("SMD"). 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.

On August 23, 2002, ISO New England and the New York Independent System Operator filed a petition with the FERC proposing to establish a single Northeastern Regional Transmission Organization ("NERTO") encompassing the six New England states and New York. If approved and established, NERTO would replace ISO New England as the entity responsible for reliability of the bulk power system, operation of the region's wholesale markets and provision of transmission throughout the region. The Company has filed comments opposing the NERTO petition, which remains pending before FERC. If the NERTO proposal is approved and implemented, the potential impacts on the Company's power supply and transmission costs are uncertain, but could be material.

On September 20, 2002, the FERC accepted in part ISO New England's request to implement a standard market design ("SMD") governing wholesale energy sales in New England. The ISO currently plans to implement its SMD plan in early 2003. SMD will include a system of locational marginal pricing of energy, under which prices will be determined by zone, and based in part on transmission congestion experienced in each zone. Initially, the State of Vermont is expected to comprise a single zone under the plan, although pricing may eventually be determined on a more localized basis. The effect of implementation of this SMD on the Company's power supply or transmission costs remains uncertain, but could be material.

MAINTENANCE EXPENSES

Maintenance expenses increased 19.7 percent or $0.3 million for the three months ended September 30, 2002 compared with the same period in 2001, primarily due to increased repair costs arising from storm damage.

Maintenance expenses increased by approximately $1.1 million or 20.5 percent during the first nine months of 2002 compared with the same period in 2001, primarily due to the costs of repair from a series of minor storms in 2002 and increases in maintenance costs at our wind generation facility located in Searsburg, Vermont.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses increased $0.1 million or 3.4 percent during the third quarter of 2002 compared with the same period in 2001 primarily due to increases in capital expenditures in 2001.

Depreciation and amortization expenses decreased $0.3 million or 2.4 percent during the first nine months of 2002 compared with the same period in 2001 primarily due to decreased amortization in 2002 of demand side management assets, partially offset by increased depreciation from capital expenditures in 2001.

TAXES OTHER THAN INCOME TAXES

Other taxes expense for the third quarter and the first nine months of 2002 were essentially unchanged compared with the same respective periods in 2001.

INCOME TAXES

Income taxes decreased $0.4 million in the third quarter of 2002 compared with the same period in 2001 due to a decrease in pretax book income from core electric operations.

Income taxes decreased $1.1 million or 18 percent for the first nine months of 2002 compared with the same period in 2001 for the same reason.

OTHER INCOME

Other income increased $0.1 million during the three months ended September 30, 2002 when compared with the same period in 2001. Our equity in earnings from VY increased approximately $0.8 million due primarily to tax benefits arising as a result of the sale of the nuclear power plant to Entergy. This increase was substantially offset by a payment of $0.5 million made to VY's non-Vermont sponsors in return for guarantees those sponsors made to Entergy to finalize the VY sale. Other income for the nine months ended September 30, 2002 was essentially unchanged from the same period in 2001.

INTEREST CHARGES

Interest charges decreased $0.2 million or 9.7 percent in the third quarter of 2002 compared with the same period in 2001, primarily due to the redemption of $8.0 million first mortgage bonds in December 2001 and $5.1 million first mortgage bonds in May 2002, partially offset by increased short-term borrowings and related interest costs.

Interest charges decreased $0.8 million or 14.8 percent in the first nine months of 2002 compared with the same period in 2001 for the same reasons.

PREFERRED STOCK DIVIDENDS

Dividends paid on preferred stock decreased $0.2 million for the quarter ended September 30, 2002 when compared with the same period in 2001, due to redemptions of preferred stock during 2002 as discussed in this section under "Liquidity and Capital Resources". Dividends paid on preferred stock decreased $0.6 million for the nine-month period ended September 30, 2002 compared with the same period in 2001, for the same reason.

LIQUIDITY AND CAPITAL RESOURCES

In the nine months ended September 30, 2002, we spent $15.3 million principally for expansion and improvements of our transmission, distribution and generation plant, and environmental expenditures. We expect to spend approximately $4.4 million during the remainder of 2002.

The Company renegotiated a 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association, ("KeyBank") with the renegotiated agreement expiring June 18, 2003 (the "Fleet-Key Agreement"). The Fleet-Key Agreement is for $35.0 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 $11.0 million outstanding with a weighted average rate of 4.0 percent on the Fleet-Key Agreement at September 30, 2002. There was no non-utility short-term debt outstanding at September 30, 2002.

On July 27, 2001, the VPSB approved a $12.0 million two-year unsecured loan agreement, with Fleet, joined by KeyBank, and the loan was made to the Company on August 24, 2001. At September 30, 2002, there was $12.0 million outstanding under the two-year loan agreement.

In its January, 2001 Order approving a 3.49% rate increase for the Company, the VPSB ordered that the Company freeze its common stock dividend rate until it had successfully replaced short-term and intermediate-term credit facilities with long-term debt or equity financing. In August 2002, the Company petitioned the VPSB for consent to issue long-term debt, with the proceeds to be used, in part, to repay existing short and intermediate-term indebtedness. On October 10, 2002, the VPSB issued an order approving the Company's petition. Pursuant to this order, upon issuance of new long-term debt and repayment of existing borrowings under the Fleet-Key Agreement and the $12.0 million two-year unsecured term loan, the dividend freeze order will terminate, allowing the Company's Board of Directors to consider an increase in the Company's common stock dividend rate. The Company expects the Board of Directors to consider whether changes in the dividend level are appropriate at its December 2002 meeting.

On October 18, 2002, the Company commenced a "Dutch Auction" self-tender offer to repurchase up to 800,000, or approximately 14%, of its common shares outstanding. The Company has also reserved the right to purchase additional shares totaling up to 2% of the outstanding shares. Shareholders may offer to sell all or a portion of the shares they own within a price range of $17.00 to $21.00. Upon completion of the tender offer, the Company will select the lowest purchase price that will allow it to purchase 800,000 shares, or such lesser number of shares actually tendered, if the total number tendered is less than 800,000 shares.

The Company is making the offer because the Board of Directors believes that the equity component of its capital structure exceeds its needs given the present outlook of the Company. The Company has adopted an average capital structure target of approximately fifty percent debt and fifty percent equity, and completion of the offer will help the Company achieve that target over time.

On March 15, 2002, the Company paid $5.3 million to redeem 10.0% first mortgage bonds due 2004. During March and June 2002, the Company paid $11.0 and $1.0 million, respectively, to redeem the 7.32 percent Class E preferred stock outstanding. On May 1, 2002, the Company paid $0.3 million to redeem the 7.0 percent Class C preferred stock outstanding.

The credit ratings of the Company's securities at September 30, 2002 were:

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

On August 29, 2002, Moody's upgraded the Company's senior secured debt rating to Baa1 from Baa2. The outlook for the ratings is stable. On September 29, 2002 Fitch Ratings upgraded the ratings of the Company's first mortgage bonds to BBB+ from BBB, with a stable outlook. On September 23, 2002, Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook.

The following table presents payments contractually due by category:

In thousands Contractual Obligations at September 30, 2002	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term Debt	$ 79,000	$ 20,000	$ 8,000	$ 14,000	$ 37,000
Revolving Credit	11,000	11,000	-		
Interest on Long Term Debt	61,672	5,457	9,020	7,994	39,201
Capital Lease.	5,640	107	852	852	3,829
Preferred Stock.	235	150	60	25	
Hydro-Quebec power supply contracts.	667,106	47,405	100,396	63,834	455,471
MS power supply contract	200,042	57,847	87,347	54,849	-
Vermont Yankee power supply contract	333,966	37,058	72,750	57,655	166,504
Total Contractual Cash Obligations .	$1,358,661	$179,023	$278,424	$199,209	$702,005

Certain amounts included in contractual obligations for Hydro-Quebec and Vermont Yankee power supply contracts include estimates of future power supply costs that could change by a material amount.

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; and

increasing volatility of wholesale market prices for electricity.

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. Recent 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.

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. In March 2002, voters in Rockingham authorized Rockingham to create a municipal utility by acquiring a municipal plant, which would include the Bellows Falls hydroelectric facility and the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. 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 our remaining customers do not subsidize a Rockingham municipal utility.

In a series of Vermont regulatory proceedings, the Company has agreed to undertake a process known as "distributed utility planning" as part of its transmission and distribution planning process. Distributed utility planning requires the Company to evaluate conservation-related alternatives and distributed generation alternatives to typical transmission and distribution capital investments. In certain circumstances, the Company may be required to implement conservation or distributed generation alternatives in lieu of, or in addition to, traditional transmission and distribution capital investments, where societal cost savings associated with conservation or distributed generation, including the costs associated with avoided electricity sales, justify the expenditures. The Company is uncertain of the potential magnitude of future spending requirements for this program, but note they could be material. Costs associated with conservation measures or distributed generation facilities not owned by the Company would be deferred as regulatory assets pending future rate proceedings.

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 plans 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 plans to make voluntary pension plan contributions totaling $2 million between September 1, 2002 and June 30, 2003, of which $500,000 has been contributed to date. The Company's pension costs and cash funding requirements could increase in future years in the absence of recovery in the equity markets.

As a result of GMP's retirement plan asset return experience, at December 31, 2002, the Company could be required to recognize an additional minimum liability as prescribed by generally accepted accounting principles. The liability would be recorded as a reduction to common equity through a charge to other comprehensive income and would not affect net income for 2002.

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, or lack thereof, 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

A sensitivity analysis has been prepared to estimate the exposure to the market price risk of our electricity commodity positions. Assumptions used in the Blacks-Scholes model include a risk free rate of 5.02 percent, locked in forward commitment prices for 2002 and 2003, a forward market price averaging approximately $60 per MWh for periods beyond 2003 with an average of approximately 60,000 MWh per year. 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. Our daily net commodity position consists of purchased electric capacity. The table below presents market risk, estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in prices. Actual prices may differ materially from the table.

Commodity Price Risk	At September 30, 2002	
	Fair Value	Market Risk
	(in thousands)	
Net short position	$ 32,615	$ 3,000

ITEM 4. CONTROLS AND PROCEDURES

Within the 90 days prior to the filing date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and its Treasurer and Controller (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934. Based upon that evaluation, the Company's Chief Executive Officer and its Treasurer and Controller 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 included in the Company's periodic SEC filings.

Since the date of the evaluation, there have been no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

GREEN MOUNTAIN POWER CORPORATION

SEPTEMBER 30,2002

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. NONE

ITEM 5. Other Information

The Company's Chief Executive Officer and the Company's Treasurer and Controller (principal financial officer) have furnished to the SEC the certification with respect to this Form 10-Q that is required by Section 906 of the Sarbanes-Oxley Act of 2002.

ITEM 6.

(A) EXHIBITS

NONE

(B) REPORTS ON FORM 8-K

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

August 14, 2002 Form 8-K announced the certification of financial statements filed with the SEC by the Chief Executive Officer and President, and the Treasurer and Controller (principal financial officer).

GREEN MOUNTAIN POWER CORPORATION

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the 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 13, 2002 /s/Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer and President

Date: November 13, 2002 /s/Robert J. Griffin

Robert J. Griffin, (as Principal Financial Officer)

Treasurer and Controller

I, Christopher L. Dutton, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Green Mountain Power Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or person performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifiying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses
Date: November 13, 2002
/s/Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer and President

I, Robert J. Griffin, certify that:
1. I have reviewed this quarterly report on Form 10-Q of Green Mountain Power Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or person performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this

quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date:November 13, 2002

/s/Robert J. Griffin

Robert J. Griffin, Treasurer and Controller (Principal Financial Officer)