GREEN MOUNTAIN POWER CORP
Form 10-Q
November 13, 2001

November 8, 2001

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, 2001

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 OR ORGANIZATION)	(I.R.S. EMPLOYER IDENTIFICATION NO.)

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 7, 2001
$3.33 1/3 PAR VALUE	5,680,253

GREEN MOUNTAIN POWER CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2001 AND 2000

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	
	2001	2000	2001	2
(in thousands, except per share data)				
OPERATING REVENUES	$76,051	$78,143	$218,319	$20
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation.	7,645	8,700	21,514	2
Company-owned generation.	1,625	1,343	3,868	
Purchases from others	45,495	49,493	129,589	12
Other operating.	3,939	3,618	11,713	1
Transmission	3,431	3,515	10,433	1
Maintenance.	1,739	1,826	5,274	
Depreciation and amortization.	3,491	3,516	10,803	1
Taxes other than income.	1,930	1,669	5,833	
Income taxes	2,183	1,192	5,870	
Total operating expenses.	71,478	74,872	204,897	20

OPERATING INCOME	4,573	3,271	13,422	
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations.	553	617	1,688	
Allowance for equity funds used during construction.	69	98	128	
Other income (deductions), net	90	(73)	16	
TOTAL OTHER INCOME.	712	642	1,832	
INCOME BEFORE INTEREST CHARGES	5,285	3,913	15,254	
INTEREST CHARGES				
Long-term debt	1,491	1,619	4,586	
Other interest	215	147	925	
Allowance for borrowed funds used during construction. . . .	(43)	(54)	(146)	
TOTAL INTEREST CHARGES.	1,663	1,712	5,365	
INCOME BEFORE PREFERRED DIVIDENDS AND. . . . . DISCONTINUED OPERATIONS	3,622	2,201	9,889	
Dividends on preferred stock	235	240	704	
Income from continuing operations.	3,387	1,961	9,185	
Loss on disposal of discontinued segment, including provisions for operating losses during phaseout period.	-	-	(150)	(
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 3,387	$ 1,961	$ 9,035	$
Common stock data				
Basic earnings (loss) per share.	$ 0.60	$ 0.36	$ 1.61	$
Diluted earnings (loss) per share.	0.58	0.36	1.56	
Cash dividends declared per share.	$ 0.14	$ 0.14	$ 0.41	$
Weighted average common shares outstanding-basic	5,644	5,505	5,615	
Weighted average common shares outstanding-diluted	5,814	5,506	5,777	
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS				
Balance - beginning of period.	$ 4,602	$ 6,389	$ 493	$ 1
Net Income	3,622	2,201	9,739	
Cash Dividends-redeemable cumulative preferred stock	(235)	(240)	(704)	
Cash Dividends-common stock.	(777)	(756)	(2,316)	(
Balance - end of period.	$ 7,212	$ 7,594	$ 7,212	$

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	FOR THE NINE MONTHS ENDED SEPTEMBER 30,	
	2001	2000

OPERATING ACTIVITIES:	(in thousands)	
Net income (loss) before preferred dividends.	$ 9,739	$ 285
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	10,803	11,659
Dividends from associated companies less equity income.	267	(18)
Allowance for funds used during construction.	(274)	(376)
Amortization of purchased power costs	2,607	4,365
Deferred income taxes	(2,525)	1,781
Excess earnings deferred.	1,050	-
Deferred purchased power costs.	(5,254)	(1,643)
Accrued purchase power contract option call	(3,346)	2,726
Provision for loss on segment disposal.	150	1,530
Arbitration costs recovered (deferred).	3,229	(3,268)
Rate levelization liability	8,613	-
Environmental and conservation deferrals, net	(2,291)	(1,957)
Changes in:		
Accounts receivable	3,594	1,713
Accrued utility revenues.	1,335	883
Fuel, materials and supplies.	37	(96)
Prepayments and other current assets.	713	455
Accounts payable.	(3,786)	571
Accrued income taxes payable and receivable	3,428	(2,396)
Other current liabilities	1,073	(4,369)
Other	455	(241)
Net cash provided by continuing operations.	29,616	11,604
Net change in discontinued segment.	(1,706)	195
Net cash provided by operating activities	27,911	11,799
INVESTING ACTIVITIES:		
Construction expenditures	(9,212)	(8,551)
Investment in nonutility property	(146)	(143)
Net cash used in investing activities	(9,358)	(8,694)
FINANCING ACTIVITIES:		
Proceeds from term loan	12,000	
Reduction in preferred stock.	-	(1,400)
Issuance of common stock.	1,283	794
(Investment in) maturity of certificate of deposit. . . .	16,173	(15,150)
Power supply option obligation.	(16,013)	15,000
Reduction in long-term debt	(1,700)	(1,700)
Short-term debt, net.	(15,500)	1,700
Cash dividends.	(3,020)	(3,035)
Net cash used in financing activities	(6,776)	(3,791)
Net increase(decrease) in cash and cash equivalents . . .	11,777	(686)
Cash and cash equivalents at beginning of period.	341	696
Cash and cash equivalents at end of period.	$ 12,118	$ 10
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for:		
Interest (net of amounts capitalized)	$ 4,677	$ 4,420

Income taxes, net	5,287	1,191

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

PART I, ITEM 1

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

(in thousands)	UNAUDITED AT SEPTEMBER 30, 2001	UNAUDITED AT SEPTEMBER 30, 2000	DECEMBER 31, 2000
ASSETS			
UTILITY PLANT			
Utility plant, at original cost	$296,843	$287,729	$291,107
Less accumulated depreciation	116,540	110,381	110,273
Net utility plant	180,303	177,348	180,834
Property under capital lease	6,449	7,038	6,449
Construction work in progress	8,208	9,535	7,389
Total utility plant, net	194,960	193,921	194,672
OTHER INVESTMENTS			
Associated companies, at equity	14,176	14,672	14,373
Other investments	6,725	6,151	6,357
Total other investments	20,901	20,823	20,730
CURRENT ASSETS			
Cash and cash equivalents	12,118	10	341
Certficate of deposit, pledged as collateral	-	15,150	15,437
Accounts receivable, less allowance for doubtful accounts of $613, $428, and $463	18,771	16,790	22,365
Accrued utility revenues	5,758	6,085	7,093
Fuel, materials and supplies, at average cost.	4,019	3,385	4,056
Prepayments	1,635	1,667	2,525
Income tax receivable	-	3,637	1,613
Other	894	459	222
Total current assets	43,195	47,183	53,652
DEFERRED CHARGES			
Demand side management programs	6,676	6,586	6,358
Purchased power costs	20,560	14,583	11,789
Pine Street Barge Canal	12,370	8,700	12,370
Other	14,697	16,200	15,519
Total deferred charges	54,303	46,069	46,036

NON-UTILITY

Other current assets	8	8	8
Property and equipment	251	252	252
Business segment held for disposal	-	7,752	-
Other assets	822	1,278	1,258
Total non-utility assets	1,081	9,290	1,518
TOTAL ASSETS	$314,440	$317,286	$316,608

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	UNAUDITED AT SEPTEMBER 30,		DECEMBER 31,
	2001	2000	2000
(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 5,656,048, 5,515,490 and 5,582,552)	$ 18,907	$ 18,438	$ 18,608
Additional paid-in capital	74,306	73,035	73,321
Retained earnings	7,212	7,594	493
Treasury stock, at cost (15,856 shares)	(378)	(378)	(378)
Total common stock equity	100,047	98,689	92,044
Redeemable cumulative preferred stock	12,560	12,795	12,560
Long-term debt, less current maturities	70,400	80,100	72,100
Term loan, maturing August 2003	12,000	-	-
Total capitalization	195,007	191,584	176,704
CAPITAL LEASE OBLIGATION	6,449	7,038	6,449
CURRENT LIABILITIES			
Current maturities of preferred stock	235	240	235
Current maturities of long-term debt	9,700	6,700	9,700
Short-term debt	-	9,600	15,500
Accounts payable, trade and accrued liabilities	5,943	4,870	7,755
Accounts payable to associated companies	6,536	8,961	8,510
Deferred excess earnings	1,050	-	-
Customer deposits	832	504	696

Purchased power call option liability.	-	9,299	8,276
Interest accrued	1,716	1,804	1,150
Energy East power supply obligation.	-	15,000	15,419
Other.	3,289	2,170	1,103
Total current liabilities.	29,301	59,148	68,344
DEFERRED CREDITS			
SFAS 133 liability	14,381	-	-
Accumulated deferred income taxes.	23,331	27,194	25,644
Unamortized investment tax credits	3,483	3,766	3,695
Pine Street Barge Canal site cleanup	10,583	8,211	11,554
Other.	21,531	20,345	20,901
Rate levelization liability.	8,613	-	-
Total deferred credits	81,922	59,516	61,794
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Liabilities of discontinued segment, net	1,761	-	3,317
Total non-utility liabilities.	1,761	-	3,317
TOTAL CAPITALIZATION AND LIABILITIES	$314,440	$317,286	$316,608

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2001

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 annual report for 2000 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. Historically we have charged our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These are called seasonally differentiated rates. In order to eliminate the impact of the seasonally differentiated rates, we defer some of the revenues from those four higher revenue months and recognize them in later periods when we have lower revenues or higher costs. By deferring certain revenues we are able to better match our revenues to our costs. On September 30, 2001, there was a deferred charge of $0.5 million, compared with $0.2 million at September 30, 2000. In the Company's most recent rate case settlement the VPSB ordered that seasonal rates be eliminated in April 2001, which is expected to generate approximately $7.5 million in additional cash flow in 2001. Such deferred revenue was intended by the VPSB to be used to offset increased costs during 2001, 2002 and 2003, increasing the likelihood that the Company will earn its allowed rate of return in those years. Approximately $8.6 million of revenue arising as a result of the elimination of seasonal rates was deferred through the third quarter of 2001. The Company expects to achieve its allowed rate of return without using any of the approximately $7.5 million in revenues expected to be deferred during 2001.

The Company's earnings from electric operations are subject to an earnings cap equal to its allowed rate of return of 11.25%. The Company's policy is to review its quarterly results and to defer any revenues that are probable of causing earnings to exceed an 11.25% rate of return ("excess earnings") for the year. As a result of our review, we deferred $0.1 million of revenue and recorded a regulatory liability for excess earnings in the same amount during the quarter ended September 30, 2001. Deferred excess earnings total $1.1 million for the nine months ended September 30, 2001. Under a settlement agreement with the Vermont Department of Public Service ("DPS" or the "Department"), and approved by the VPSB, any excess earnings amounts will be used to write off regulatory assets at December 31, 2001.

The Company reviews its deferred revenue balances arising from excess earnings and rate levelization each quarter and adjusts those balances as necessary to reflect the Company's current estimate of its ultimate regulatory liability. See the discussion under "Commitments and Contingencies - Retail Rate Cases" for further information.

Certain line items on the prior years' 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", formerly known as Mountain Energy, Inc.); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; and Green Mountain Resources, Inc. ("GMRI"). On June 30, 1999, we decided to sell the assets of NWR, and reported its results as income (loss) from operations of a discontinued segment. 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 unregulated subsidiaries (excluding NWR) and the rental water heater program are included 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 significant ownership interests) listed below based on our percentage ownership (equity method).

VERMONT YANKEE NUCLEAR POWER CORPORATION ("VY")

Percent ownership: 17.9% common

	Three months ended September 30	Nine months ended September 30

(in thousands)	2001	2000	2001	2000
Gross Revenue.	$37,868	$44,648	$135,863	$130,042
Net Income Applicable. to Common Stock	1,641	1,559	4,765	4,942
Equity in Net Income .	296	275	856	890

On October 15, 1999, the owners of VY accepted a bid from AmerGen for the VY generating plant, intending to complete the sale before December 2000. AmerGen and the DPS negotiated a revised offer in November 2000, which was subsequently dismissed as insufficient by the VPSB in February 2001. Prior to the dismissal of the AmerGen offer, Entergy Nuclear Inc. had also made an offer, secured by a bond which was acceptable to the VPSB, and two other companies indicated they would participate in an auction, if held. VY has conducted an auction of the plant.

On August 15, 2001, VY agreed to sell its nuclear power plant to Entergy Corporation for approximately $180 million. The sale is subject to approval of the VPSB, the U.S. Nuclear Regulatory Commission, the Federal Energy Regulatory Commission and other regulatory bodies. A related agreement calls for Entergy to provide the current output level of the plant to VY's present sponsors, including GMP, at average annual prices ranging from $39 to $45 per megawatt hour through 2012. No decommissioning top-off or any other financing by VY is anticipated to complete the transaction. The sale, if completed, will lower projected costs over the remaining license period for VY. The Company would continue to own its equity interest in VY.

VERMONT ELECTRIC POWER COMPANY, INC.("VELCO")
Percent ownership: 29.5% common
30.0% preferred

	Three months ended September 30		Nine months ended September 30	
(in thousands)	2001	2000	2001	2000
Gross Revenue	$6,806	$7,011	$22,524	$21,151
Net Income.	230	309	782	892
Equity in Net Income.	75	93	221	267

VELCO is engaged in the transmission of electric power within the State of Vermont(the "State"). VELCO has entered into transmission agreements with the State 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.

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, 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("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, 2001, our total expenditures related to the Pine Street site since 1982 were approximately $24.7 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 awaiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals 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 approximately $12.4 million over the next 32 years. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We also have recorded an offsetting regulatory asset, and we believe that it is probable that we will receive future revenues to recover these costs.

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

We proposed in our rate filing made on June 16, 1997 recovery of an additional $3.0 million in such expenditures. In an Order in that case released March 2, 1998, the VPSB suspended the recovery 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

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

The Company reached a final settlement agreement with the Department in the 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 over the past three years;
* 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 annual 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 all or substantially all of its short-term credit facilities with long-term debt or equity financing;
* Seasonal rates were eliminated in April 2001, which is expected to generate approximately $7.5 million in additional cash flow in 2001 that can be utilized to offset potential increased costs during 2001, 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; and
* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the Company's 1997 rate case. The Company agreed to an earnings cap for its electric operations in an amount equal to its allowed rate of return of 11.25 percent. Amounts earned over the cap will be used to write-off regulatory assets.

On January 23, 2001, the VPSB Order (the "Settlement Order") approved the Company's settlement with the Department, with two additional conditions:

* The Settlement Order provided that the Company and its customers 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.

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 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 cumulative amount of power purchased by Hydro-Quebec under option B is approximately 432,000 MWh. Approximately $6.6 million is currently being provided annually in rates to cover the net cost of 9701 calls by Hydro-Quebec. The Company recognized $5.0 million in net expense during the nine months ended September 30, 2001 to reflect these 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. In conjunction with the Settlement Order, Hydro-Quebec agreed not to call option B during 2002.

If estimated costs of fulfilling the Hydro-Quebec option calls exceed amounts recovered in rates and/or amounts previously recorded, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first nine months of 2001. No charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2001. It is possible our estimate of future power supply costs could differ materially from actual results.

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 through 2015, 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.

During 1999, the Company had accrued expected losses for 2000 for disallowed Hydro-Quebec power supply contracts pursuant to VPSB orders. Results for the three and nine months ended September 30, 2000 do not reflect any disallowed Hydro-Quebec power supply costs. If the 1999 accruals, consistent with generally accepted accounting principles, had not been made, power supply costs would have been $1.9 and $5.7 million higher for the three and nine months ended September 30, 2000, respectively.

POWER SUPPLY AND TRANSMISSION

A FERC ruling in December 2000 required the New England Independent System Operator ("ISO") to revise its installed capability ("ICAP") deficiency charge of $0.17 per kw month to $8.75 per kw month retroactive to August 1, 2000. On January 10, 2001, FERC stayed its order "to ensure that bills for past periods will not be assessed until the Commission has considered the pending requests for rehearing, which, if successful, would then require extensive refunds and surcharges." On March 6, 2001, FERC issued an Order on Rehearing in which it partly reversed itself on the ICAP charge. Although the FERC first concluded that a $8.75 charge is reasonable and that the charge would remain in place until the ISO supports an acceptable superseding proposal, the FERC then concluded that reinstating the $8.75 would have an adverse cost impact, and should be effective only as of April 1, 2001. The FERC allowed the $8.75 charge to become effective on April 1, 2001 until the effective date of any superseding charge that the FERC might accept.

In March 2001, a federal court issued a stay preventing reinstatement of the $8.75 charge, after sixteen New England utilities and energy companies protested the increased penalty. The federal court lifted the stay but ordered FERC to further justify its decision and said that a $5 per kW month rate might be more appropriate. A final default rate of $4.87 was approved by FERC effective September 2001. The FERC order provides a fourteen day cure period each month during which utilities may make bilateral purchases to fulfill ICAP deficiencies and avoid the default rate. The Company's generation and entitlements cover the majority of its ICAP requirements, except during periods in which Hydro-Quebec calls for power under 9701. The Company has purchased its expected ICAP requirements for 2001 at an average price of approximately $4.06 per kW month. The Company has also arranged to purchase its anticipated ICAP needs during 2002 at an average cost of $2.55 per kW month, and the majority of its anticipated ICAP needs during 2003 at a cost of $2.85 per kW month.

On April 17, 2001, an Arbitration Tribunal issued its decision in the arbitration brought by a group of Vermont electric companies and municipal utilities, known as the Vermont Joint Owners (VJO), against Hydro-Quebec for its failure to deliver electricity pursuant to the VJO/Hydro-Quebec power supply contract during the 1998 ice storm. The Company is a member of the VJO.

In its award, the Arbitration Tribunal agreed partially with Hydro-Quebec and partially with the VJO. In the decision, the Tribunal concluded (i) the VJO/Hydro-Quebec power supply contract remains in effect and Hydro-Quebec is required to continue to provide capacity and energy to the Company under the terms of the VJO contract, which expires in 2015 and (ii) Hydro-Quebec is required to return certain capacity payments to the VJO.

On July 23, 2001, the Company received approximately $3.2 million representing its share of refunded capacity payments from Hydro-Quebec. These proceeds reduced related deferred assets at June 30, 2001, leaving a deferred balance of unrecovered arbitration costs of approximately $1.4 million. We believe it is probable that this balance will ultimately be recovered in rates.

4. SEGMENTS AND RELATED INFORMATION

The Company has two reportable segments, the electric utility and NWR. 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, 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 June 30, 1999, we classified NWR's net assets and liabilities as "Business Segment Held for Sale", reflecting the Company's intent to sell NWR's assets. Previously, investment in NWR appeared as a separate caption, "Equity Investment in Energy Related Business" in the nonutility section of the consolidated balance sheet.

During 2000, the Company recorded losses of $6.5 million, or $1.19 per share to reflect revised estimates and actual sales of most of NWR's energy generation and energy efficiency assets. During the quarter ended June 30, 2001, the Company recorded a provision for loss of approximately $0.2 million or 3 cents per share related to a revision to its estimate of the ultimate costs of warranty obligations on its waste-water investments. The provisions for loss from discontinued operations reflect the Company's most recent estimate. The ultimate loss remains subject to the sale or other disposition of NWR's remaining assets and liabilities, primarily patents and warranty claims, and tax liabilities, and could exceed amounts recorded. Results of operations for NWR are now reported under "Loss on disposal of discontinued segment, net of applicable income taxes". Provisions for loss on disposal are reported under "Loss on disposal of discontinued segment, net of applicable income taxes". Segment information compared with the Company's results includes the following:

	Three months ended September 30		Nine months ended September 30	
	2001	2000	2001	2000
(in thousands, except per share data)				
External revenues				
Electric utility	$76,051	$78,143	$218,319	$207,782
NWR segment.	33	733	138	1,351
Net income (loss) from operations				
Electric utility	$ 3,387	$ 1,961	$ 9,185	$ 1,036

NWR segment.	-	-	(150)	(1,530)
Consolidated net income (loss). . . .	$ 3,387	$ 1,961	$ 9,035	$ (494)
Basic earnings (loss) per share				
Discontinued operations.	$ -	$ -	$ (0.03)	$ (0.28)
Continuing operations.	0.60	0.36	1.64	0.19
Diluted earnings per share				
Discontinued operations.	$ -	$ -	$ (0.03)	$ (0.28)
Continuing operations.	0.58	0.36	1.59	0.19

5. NEW ACCOUNTING STANDARD - SFAS 133

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. 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. Accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement or other comprehensive income and requires that hedges be formally documented, designateed, and assessed for effectiveness. SFAS 133, as amended by SFAS 137, was effective for the Company beginning the first quarter of 2001. SFAS 133 must be applied to (a) derivative instruments and (b) either all derivative instruments embedded in hybrid contracts or those embedded instruments that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

The objective of the Company's risk management program is to protect 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 counterparties that have at least investment grade ratings. These transactions are used to hedge risk of fossil fuel price increases as well as the risk of spot market electricity price increases. Futures, swaps and forward contracts are used to hedge market prices should option calls by Hydro-Quebec be exercised. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and limits to transaction authority.

The Company's 9701 arrangement with Hydro-Quebec that grants Hydro-Quebec an option to call for energy deliveries at prices currently below estimated future market rates through 2015 is a derivative under SFAS 133. We sometimes use futures contracts (derivatives) to hedge forecasted sales of electric power, including the 9701 arrangement. The Company also has a power purchase and supply agreement with Morgan Stanley Capital Group, Inc. ("MS") to hedge the fair value of fossil fuel prices that is a derivative under 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 effects 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, 2001, the Company had a liability reflecting the negative market position of the two derivatives described above, as well as a corresponding regulatory asset of approximately $14.4 million related to the derivatives discussed above. The Company believes that the regulatory asset is probable of recovery. The regulatory asset 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.

6. OTHER 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 and uses a nonamortization approach to purchased goodwill and other intangible assets. SFAS 142 establishes requirements for evaluating goodwill and other intangible assets for impairment and provides further guidance on accounting for intangible assets. The Company does not expect the application of these accounting standards, when adopted, to materially impact its financial position or results of operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS") which provides guidance on accounting for nuclear plant decommissioning costs. The Company has not yet determined what impact, if any, the accounting standard will have on its investment in VY.

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 period presented. The Company established a stock incentive plan for all 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	
	2001	2000	2001	2000
(in thousands)				
Net income (loss) before preferred dividends.	$3,622	$2,201	$9,739	$ 285
Preferred stock dividend requirement.	235	240	704	779
Net income (loss) applicable to common stock.	$3,387	$1,961	$9,035	$ (494)
Average number of common shares-basic	5,644	5,505	5,615	5,471
Dilutive effect of stock options.	170	1	162	1
Anti-dilutive stock options	-	-	-	-
Average number of common shares-diluted . . .	5,814	5,506	5,777	5,472

GREEN MOUNTAIN POWER CORPORATION
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
SEPTEMBER 30, 2001

PART I -- ITEM 2

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.

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 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 (loss) per share of Common Stock

	Three months ended September 30		Nine months ended September 30	
	2001	2000	2001	2000
Utility business . . .	$0.58	$0.33	$ 1.57	$ 0.11
Unregulated businesses	0.02	0.03	0.07	0.08
Earnings(loss) from: . Continuing operations	0.60	0.36	1.64	0.19
Discontinued segment .	-	-	(0.03)	(0.28)
Basic earnings (loss) per share . .	$0.60	$0.36	$ 1.61	$(0.09)

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of $0.58 in the quarter ended September 30, 2001, compared with earnings of $0.33 per share in the third quarter of 2000.

The third quarter earnings improvement, compared with the same period for 2000, reflects higher retail operating revenues. Retail operating revenues for the quarter increased $3.5 million compared with the same period in 2000, reflecting a 3.42 percent retail rate increase (the "Settlement Order") approved by the Vermont Public Service Board (the "VPSB") in January 2001 and a 5.0 percent increase in retail electricity sales.

Power supply costs were $4.8 million lower in the third quarter of 2001, primarily due to a $6.4 million decrease in low margin wholesale sales of electricity, offset in part by adjustments that caused approximately $1.9 million in power supply costs paid during 2000 to be expensed in previous periods, as discussed below.

Basic earnings per share from utility operations for the nine months ended September 30, 2001 were $1.57 compared with earnings per share of $0.11 for the same period in 2000, due to the same revenue factors influencing third quarter results, and to decreased power supply expense associated with the management of the Company's long-term sale commitment to Hydro-Quebec("9701"), lower Vermont Yankee costs due to the timing of scheduled outages, a refund of certain administrative costs from the New England Independent System Operator("ISO") and lower costs from independent power producers.

The Company had previously accrued losses for disallowed Hydro-Quebec power supply costs pursuant to VPSB orders. Results for the nine months ended September 30, 2000 do not reflect any disallowed Hydro-Quebec power supply costs. If these accruals, consistent with generally accepted accounting principles, had not been made in prior periods, power supply costs would have been $1.9 and $5.7 million higher, respectively, for the three and nine months ended September 30, 2000.

UNREGULATED BUSINESSES

Earnings from unregulated businesses included in results from continuing operations for the three and nine months ended September 30, 2001 were slightly lower than during the same period in 2000. A financial summary for these businesses, excluding NWR, follows:

	Three months ended September 30		Nine months ended September 30	
(in thousands)	2001	2000	2001	2000
Revenue. . . .	$ 251	$ 259	$ 761	$ 780
Expense. . . .	139	99	395	341
Net Income . .	$ 112	$ 160	$ 366	$ 439

DISCONTINUED SEGMENT OPERATIONS

As of June 30, 1999, the Company decided to sell or dispose of NWR, a wholly owned subsidiary that invested in energy generation, energy efficiency and wastewater treatment businesses. Its results are reported separately after income (loss) from continuing operations. NWR recognized an additional $0.2 million as a provision for loss for the nine months ended September 30, 2001 reflecting revised estimates of losses on warranty liabilities. The ultimate loss remains subject to the sale or other disposition of NWR's remaining assets and liabilities, primarily patents and warranty claims and tax liabilities, and could exceed amounts recorded. Most of NWR's energy generation and energy efficiency assets have been sold. Without discontinued operations treatment, the operating loss for the three months ended September 30, 2001 would have been approximately $0.1 million compared with a loss of $0.2 million for the same period a year ago. The operating loss for the nine months ended September 30, 2001 would have been approximately $0.4 million compared with a loss of $1.0 million for the same period in 2000.

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, 2001 and 2000 are summarized below:

	Three months ended September 30		Nine months ended September 30	
	2001	2000	2001	2000
(dollars in thousands)				
Operating revenues				
Retail.	$ 49,009	$ 45,482	$ 146,548	$ 138,567
Sales for Resale. . .	25,579	31,968	68,177	$ 66,898
Other	1,463	693	3,594	$ 2,317
Total Operating Revenues.	$ 76,051	$ 78,143	$ 218,319	$ 207,782
MWh sales-Retail.	499,671	475,952	1,475,820	1,449,017
MWh sales for Resale. . .	673,868	798,317	1,857,252	1,954,277
Total MWh Sales	1,173,539	1,274,269	3,333,072	3,403,294

Average Number of Customers

	Three months ended September 30		Nine months ended September 30	
	2001	2000	2001	2000
Residential	73,075	72,557	73,161	72,288
Commercial and Industrial	12,998	12,835	12,986	12,690
Other	66	67	65	65
Total Number of Customers. .	86,139	85,459	86,212	85,043

REVENUES

Revenues from operations in the third quarter of 2001 decreased $2.1 million or 2.7 percent compared with the same period in 2000. Operating revenues result from retail and wholesale sales of electricity.

Retail revenues in the third quarter of 2001 were $3.5 million or 7.8 percent higher compared with the same period in 2000, reflecting a 3.42 percent rate increase effective January 2001, and a 5.0 percent increase in retail MWh sales. Sales of electricity increased by 6.5 percent to small commercial and industrial customers, increased by 4.8 percent to residential customers and increased 2.7 percent to lower margin industrial customers during the third quarter of 2001

compared with the same period in 2000. The increase in retail MWh sales was primarily due to warmer summer temperatures and customer growth.
Retail revenues for the nine months ended September 30, 2001 were $8.0 million or 5.8 percent higher when compared with the same period in 2000, reflecting the Settlement Order rate increase and increased retail MWh sales of approximately 1.8 percent.

In the Company's most recent rate case settlement the VPSB ordered that seasonal rates be eliminated in April 2001, which is expected to generate approximately $7.5 million in additional cash flow in 2001. Such deferred revenue was intended by the VPSB to be used to offset increased costs during 2001, 2002 and 2003, increasing the likelihood of the Company earning its allowed rate of return in those years. Approximately $8.6 million of revenue arising as a result of the elimination of seasonal rates was deferred through the third quarter of 2001. The Company expects to achieve its allowed rate of return without utilizing any of the approximate $7.5 million in revenues expected to be deferred during 2001.

The Company's earnings from electric operations are subject to an earnings cap equal to its allowed rate of return of 11.25%. The Company's policy is to review its quarterly results and to defer any revenues that are probable of causing earnings to exceed an 11.25% rate of return ("excess earnings") for the year. As a result of our review, we deferred $0.5 million of revenue and recorded a regulatory liability for excess earnings in the same amount during the quarter ended September 2001. Deferred excess earnings total $1.1 million for the nine months ended September 30, 2001. Under a settlement agreement with the Vermont Department of Public Service ("DPS" or the "Department"), and approved by the VPSB, any excess earnings amounts will be used to write off regulatory assets at December 31, 2001.
We sell wholesale electricity to others for resale. Our revenue from wholesale sales of electricity decreased $6.4 million in the third quarter of 2001 compared with the same period in 2000, due to a decrease in resales under a power purchase and supply agreement between the Company and Morgan Stanley Capital Group, Inc. ("MS"), and decreased sales under various arrangements with Hydro-Quebec. Under the MS agreement, we sell power to MS at predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements.
Our revenue from wholesale sales of electricity increased $1.3 million for the first nine months of 2001 compared with the same period in 2000. The increases were due primarily to increased sales to the ISO.

OPERATING EXPENSES
POWER SUPPLY EXPENSES

Power supply expenses decreased $4.8 million or 8.0 percent in the third quarter of 2001 compared with the same period in 2000.

Power supply expenses at Vermont Yankee decreased $1.1 million or 12.1 percent during the third quarter of 2001 compared with the third quarter of 2000, primarily due to reduced maintenance costs. A proposed sale of the generating plant is discussed under Part I, Item 2, "Investment in Associated Companies".

Company-owned generation expenses increased $0.3 million or 21.0 percent in the third quarter of 2001 compared with the same period in 2000 primarily due to higher fuel prices

The cost of power that we purchased from other companies decreased $4.0 million or 8.1 percent in the third quarter of 2001 compared with the same period in 2000, primarily due to decreased wholesale sales of electricity of $6.4 million, offset in part by higher energy and capacity costs and adjustments that caused approximately $1.9 million in power supply costs paid during 2000 to be expensed in previous periods.Power supply expenses for the first nine months of 2001 decreased $3.9 million or 2.4 percent when compared with the first nine months of 2000.
Power supply expense at Vermont Yankee decreased $4.9 million or 18.5 percent for the first nine months of 2001 compared with the first nine months of 2000, primarily due to a scheduled outage at the plant during 2001. Vermont Yankee

scheduled outage costs are deferred and amortized over an eighteen month refueling cycle.

Company-owned generation expenses decreased $0.4 million or 9.1 percent in the first nine months of 2001 compared with the same period in 2000. During 2001, the Company recorded a reduction of generation expense of approximately $1.9 million for its costs of running peak generation facilities for system reliability and we received reimbursement of these amounts from the ISO in July 2001. This reduction was partially offset by increased generation expense caused by higher fuel costs.

Purchased power expense increased $1.4 million or 1.1 percent in the first nine months of 2001 compared with the first nine months of 2000. Power supply costs increased due to accounting adjustments that caused approximately $5.7 million of power supply costs paid during 2000 to be expensed in previous periods, higher energy prices and the costs of energy purchased to cover potential shortfalls due to transmission system operating requirements. These increases were offset in part by decreased costs of managing the replacement costs of power sold to Hydro-Quebec under 9701during 2001.

The 9701 arrangement allows Hydro-Quebec to exercise an option to purchase power from the Company at energy prices based on a 1987 contract. During the first quarter of 2001, Hydro-Quebec exercised its purchase option for delivery of 134,592 MWh during the months of June, July and August of 2001. The Settlement Order approved by the VPSB includes revenues in 2001 sufficient to provide for net costs for replacing power purchased by Hydro-Quebec of approximately $6.6 million annually. The Company recognized $1.6 million in expense during the quarter ended September 30, 2001 to reflect these 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 to be recovered during 2001. If the estimated costs of power purchased to supply Hydro-Quebec option calls exceed amounts recovered in rates and/or amounts previously recorded, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first nine months of 2001. The Company purchased power sufficient to fulfill the 9701 calls for this summer, and no charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2001. The net cost of power to supply all 9701 option calls during 2001 is estimated at approximately $8.4 million. It is possible our estimate of future power supply costs could differ materially from actual results.

Both the 9701 arrangement and our 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, 2001, the Company had a regulatory asset of approximately $14.4 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.

OTHER OPERATING EXPENSES

Other operating expenses increased $0.3 million or 8.9 percent in the third quarter of 2001 compared with the same period in 2000. The increase reflects higher outside service costs and increased benefit costs. Other operating expenses increased $0.8 million or 7.3 percent in the first nine months of 2001 compared with the same period in 2000 for the same reasons, offset in part by reduced regulatory commission expenses.

TRANSMISSION EXPENSES

Transmission expenses decreased by approximately $0.1 million or 2.4 percent for the three months ended September 30, 2001 compared with the same period in 2000 due to minor reductions in congestion charges. Transmission expenses decreased by approximately $0.2 million or 1.6 percent for the nine months ended September 30, 2001, compared with the same period in 2000 for the same reason. Congestion charges recorded in the first nine months of 2001 and

2000 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. The Company is unable to predict the magnitude or duration of future congestion charge allocations, but amounts could be material.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses were essentially unchanged during the third quarter of 2001 compared with the same period in 2000.

Depreciation and amortization expenses decreased $0.9 million or 7.3 percent during the first nine months of 2001 compared with the same period in 2000. The reduction is primarily due to decreased amortization of demand side management regulatory assets.

TAXES OTHER THAN INCOME TAXES

Other taxes increased $0.3 million or 15.6 percent in the third quarter of 2001 compared with the same period in 2000, primarily due to increases in property and gross revenue tax. Other taxes increased $0.4 million or 6.8 percent for the first nine months of 2001 compared with the same period in 2000 for the same reason.

INCOME TAXES

Income taxes increased $1.0 million in the third quarter of 2001 compared with the same period in 2000 due to an increase in pretax book income. Income taxes increased $5.5 million for the first nine months of 2001 compared with the same period in 2000 for the same reason.

OTHER INCOME

Other income increased $0.1 million or 10.9 percent for the three months ended September 30, 2001 compared with the same period in 2000. Other income decreased $0.3 million or 13.6 percent for the nine months ended September 30, 2001, compared with the same period in 2000 due primarily to a favorable settlement of a claim in the first quarter of 2000 and reductions in capitalized returns during construction in 2001.

INTEREST CHARGES

Interest charges decreased $49,000 or 2.9 percent in the third quarter of 2001 compared with the same period in 2000 primarily due to reductions in interest on long-term debt due to sinking fund redemption.

Interest charges increased $0.2 million or 3.3 percent for the nine months ended September 30, 2001 compared with the same period in 2000 primarily due to increased costs associated with the short term credit arrangements discussed under "Liquidity and Capital Resources" offset in part by reductions in interest on long-term debt due to sinking fund redemption.

LIQUIDITY AND CAPITAL RESOURCES

In the nine months ended September 30, 2001, we spent $9.9 million principally for expansion and improvements of our transmission and distribution plant. We expect to spend an additional $5.9 million during the remainder of 2001.

On June 20, 2001, we renewed a revolving credit agreement (the "Fleet Agreement") with Fleet National Bank ("Fleet"), joined by KeyBank National Association ("KeyBank"). The Fleet Agreement is for a period of 364 days, will expire on June 19, 2002, and is unsecured. No amounts were outstanding on the Fleet Agreement at September 30, 2001.

On September 20, 2000, we established a $15.0 million revolving credit agreement with KeyBank (the "KeyBank Agreement") which expired on September 19, 2001. Pursuant to a September 2000 one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds were not returned to EE. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the

Company to secure the repayment of loans made pursuant to the Keybank Agreement. The payment made by EE was returned to EE along with accrued interest on September 11, 2001.

The Company executed and delivered a $12.0 million two-year loan agreement with Fleet, joined by KeyBank. Funding of this facility was contingent upon VPSB approval. On July 27, 2001 the VPSB approved the financing arrangement and the loan was funded on August 24, 2001. The Company used this facility, along with proceeds from the maturing KeyBank certificate of deposit, to terminate the KeyBank Agreement, and repay the $15.0 million it received from EE pursuant to the power supply option agreement discussed above. At September 30, 2001, there was $12.0 million outstanding under the two-year loan agreement.

The credit ratings of the Company's securities are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB	Baa2	BBB
Preferred stock	BBB-	Ba2	BB

COMPETITION AND RESTRUCTURING

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

* Disparity in electric rates, transmission, and generation capacity among and within various regions of the country;
* Improvements in generation efficiency;
* Alternative energy sources;
* The deregulation of the wholesale energy market and the establishment of an independent system operator; and
* New regulations and legislation in some states intended to foster competition, also known as restructuring.

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.

NUCLEAR DECOMMISSIONING

The staff of the SEC has questioned certain current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating units in financial statements. In response to these questions, the Financial Accounting Standards Board ("FASB") had agreed to review the accounting for closure and removal costs, including decommissioning. The FASB issued a new statement on accounting standards in August 2001 for "Obligations Associated with Disposal Activities", which provides guidance on accounting for nuclear plant decommissioning costs. The Company has not yet determined what impact, if any, the new accounting standard will have on its investment in VY.

EFFECTS OF INFLATION

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

MARKET RISK

In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133, as amended by SFAS 137, is effective for the Company beginning the first quarter of 2001. SFAS 133 must be applied to (a) derivative instruments and (b) either all derivative instruments embedded in hybrid contracts or those embedded instruments that were issued, acquired, or substantively modified on or after January 1, 1998 or January 1, 1999 (as elected by the Company).

The objective of the Company's risk management program is to protect cash flow and earnings by minimizing risk. Permitted transactions 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 risk of fossil fuel price increases as well as the risk of spot market electricity price increases. Futures, swaps and forward contracts are used to hedge the impact of market prices on the Company should option calls by Hydro-Quebec be exercised by Hydro-Quebec. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and limits to transaction authority.

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

	At September 30, 2001 Fair value	Market risk
(in thousands)		
Highest long position .	$ 19,582	$ 15,880
Highest short position.	$ 35,775	$ 13,785
Average position(short)	$ (16,192)	$ 2,095

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GREEN MOUNTAIN POWER CORPORATION

SEPTEMBER 30,2001

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
NONE

ITEM 6. (B) REPORTS ON FORM 8-K

The following Form 8-K was filed by the Company on the topic and date indicated:

August 15, 2001 Form 8-K announced an agreement between Vermont Yankee Nuclear Power Corporation ("Vermont Yankee") and Entergy Corporation to sell Vermont Yankee's nuclear power plant to Entergy for approximately $180 million. The Company owns approximately 17.9% of the common stock of Vermont Yankee.

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 09, 2001 /s/Nancy Rowden Brock

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