GREEN MOUNTAIN POWER CORP
Form 10-Q
May 10, 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 MARCH 31, 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 MAY 2, 2001
$3.33 1/3 PAR VALUE	5,623,848

GREEN MOUNTAIN POWER CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE MONTHS ENDED MARCH 31,
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 MARCH 31	
	2001	2000
In thousands, except per share data		
OPERATING REVENUES	$74,796	$67,712
OPERATING EXPENSES		
Power Supply		
Vermont Yankee Nuclear Power Corporation	8,044	8,060
Company-owned generation	2,376	1,204
Purchases from others	44,016	36,646
Other operating	3,368	3,627
Transmission	3,459	3,483
Maintenance	1,457	1,626
Depreciation and amortization	3,689	4,167
Taxes other than income	1,988	2,027
Income taxes	1,824	2,259
Total operating expenses	70,221	63,099
OPERATING INCOME	4,575	4,613
OTHER INCOME		
Equity in earnings of affiliates and non-utility operations	550	624

Allowance for equity funds used during construction.	14	62
Other income (deductions), net	(27)	185
TOTAL OTHER INCOME (DEDUCTIONS)	537	871
INCOME BEFORE INTEREST CHARGES	5,112	5,484
INTEREST CHARGES		
Long-term debt	1,547	1,661
Other interest	478	144
Allowance for borrowed funds used during construction. . . .	(62)	(40)
TOTAL INTEREST CHARGES.	1,963	1,765
INCOME BEFORE PREFERRED DIVIDENDS AND. . . . . DISCONTINUED OPERATIONS	3,149	3,719
Dividends on preferred stock	235	270
Income from continuing operations.	2,914	3,449
Net income from discontinued segment operations	-	-
Loss on disposal, including provisions for operating losses during phaseout period.	-	-
NET INCOME APPLICABLE TO COMMON STOCK.	$ 2,914	$ 3,449
Common stock data		
Basic earnings per share	$ 0.52	$ 0.63
Diluted earnings per share	0.51	0.63
Cash dividends declared per share.	$ 0.14	$ 0.14
Weighted average common shares outstanding-basic	5,588	5,437
Weighted average common shares outstanding-diluted	5,741	5,437
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS		
Balance - beginning of period.	$ 493	$10,344
Net Income	3,149	3,719
Cash Dividends-redeemable cumulative preferred stock	(235)	(270)
Cash Dividends-common stock.	(768)	(747)
Balance - end of period.	$ 2,639	$13,046

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

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	FOR THE THREE MONTHS ENDED MARCH 31	
	2001	2000
OPERATING ACTIVITIES:	In thousands	
Net income before preferred dividends	$ 3,149	$ 3,719
Adjustments to reconcile net income to net cash provided by operating activities:		

Depreciation and amortization	3,689	4,167
Dividends from associated companies less equity income	41	(111)
Allowance for funds used during construction	(76)	(102)
Amortization of purchased power costs	1,015	1,500
Deferred income taxes	(173)	447
Deferred revenues	7,218	7,163
Deferred purchased power costs	551	54
Accrued purchase power contract option call	(1,580)	-
Deferred arbitration costs	61	(457)
Environmental and conservation deferrals, net	(840)	(542)
Changes in:		
Accounts receivable	(2,821)	(1,836)
Accrued utility revenues	214	(50)
Fuel, materials and supplies	926	18
Prepayments and other current assets	1,122	1,487
Accounts payable	(5,138)	611
Accrued income taxes payable and receivable	1,868	1,997
Other current liabilities	1,063	(1,671)
Other	(755)	1,297
Net cash provided by continuing operations	9,532	17,691
Net change in discontinued segment	-	(320)
Net cash provided by operating activities	9,532	17,371
INVESTING ACTIVITIES:		
Construction expenditures	(2,350)	(1,852)
Investment in nonutility property	(46)	(44)
Net cash used in investing activities	(2,397)	(1,896)
FINANCING ACTIVITIES:		
Issuance of common stock	461	301
Investment in certificate of deposit, pledged for revolver.	(245)	-
Power supply option obligation	370	-
Short-term debt, net	(6,600)	(7,900)
Cash dividends	(1,003)	(1,017)
Net cash used in financing activities	(7,017)	(8,616)
Net increase(decrease) in cash and cash equivalents	119	6,859
Cash and cash equivalents at beginning of period	341	696
Cash and cash equivalents at end of period	$ 460	$ 7,555
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid year-to-date for:		
Interest (net of amounts capitalized)	$ 1,354	$ 1,029
Income taxes, net	-	-

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 MARCH 31,		DECEMBER 31,
	2001	2000	2000
In thousands			
ASSETS			
UTILITY PLANT			
Utility plant, at original cost	$291,034	$285,071	$291,107
Less accumulated depreciation	111,877	105,490	110,273
Net utility plant	179,157	179,581	180,834
Property under capital lease.	6,449	7,038	6,449
Construction work in progress	8,567	5,310	7,389
Total utility plant, net.	194,173	191,929	194,672
OTHER INVESTMENTS			
Associated companies, at equity	14,332	14,653	14,373
Other investments	6,485	5,990	6,357
Total other investments	20,817	20,643	20,730
CURRENT ASSETS			
Cash and cash equivalents	460	7,514	341
Certficate of deposit, pledged as collateral.	15,681	-	15,437
Accounts receivable, customers and others, less allowance for doubtful accounts of $463, $398, and $463	25,186	20,339	22,365
Accrued utility revenues.	6,880	7,019	7,093
Fuel, materials and supplies, at average cost	3,130	3,272	4,056
Prepayments	1,375	1,591	2,525
Income tax receivable	-	-	1,613
Other	249	217	222
Total current assets.	52,961	39,952	53,652
DEFERRED CHARGES			
Demand side management programs	6,363	7,158	6,358
Purchased power costs	41,692	11,281	11,789
Pine Street Barge Canal	12,370	8,700	12,370
Other	15,901	17,456	15,519
Total deferred charges.	76,326	44,595	46,036
NON-UTILITY			
Cash and cash equivalents	-	41	-
Other current assets.	8	8	8
Property and equipment.	251	253	252
Business segment held for disposal.	-	9,797	-
Other assets.	862	1,306	1,258
Total non-utility assets.	1,121	11,405	1,518
TOTAL ASSETS.	$345,398	$308,524	$316,608

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

In thousands except share data	UNAUDITED AT MARCH 31, 2001	UNAUDITED AT MARCH 31, 2000	DECEMBER 31, 2000
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION			
Common stock equity			
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,617,116, 5,463,948 and 5,582,552)	$ 18,723	$ 18,215	$ 18,608
Additional paid-in capital	73,668	72,766	73,321
Retained earnings.	2,639	13,046	493
Treasury stock, at cost (15,856 shares).	(378)	(378)	(378)
Total common stock equity.	94,652	103,649	92,044
Redeemable cumulative preferred stock.	12,560	12,795	12,560
Long-term debt, less current maturities.	72,100	81,800	72,100
Total capitalization	179,312	198,244	176,704
CAPITAL LEASE OBLIGATION	6,449	7,038	6,449
CURRENT LIABILITIES			
Current maturities of preferred stock.	235	1,640	235
Current maturities of long-term debt	9,700	6,700	9,700
Short-term debt.	8,900	-	15,500
Accounts payable, trade and accrued liabilities.	4,566	6,814	7,755
Accounts payable to associated companies	6,561	7,057	8,510
Dividends declared	229	285	229
Customer deposits.	753	351	696
Purchased power call option liability.	6,696	-	8,276
Interest accrued	1,753	1,883	1,150
Energy East power supply obligation.	15,789	-	15,419
Deferred revenues.	7,218	7,163	-
Other.	1,532	6,127	874
Total current liabilities.	63,932	38,020	68,344
DEFERRED CREDITS			
SFAS 133 liability	31,517	-	-
Accumulated deferred income taxes.	25,541	25,718	25,644

Unamortized investment tax credits	3,625	3,907	3,695
Pine Street Barge Canal site cleanup	11,140	8,985	11,554
Other.	20,565	26,612	20,901
Total deferred credits	92,388	65,222	61,794
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Liabilities of discontinued segment, net	3,317	-	3,317
Total non-utility liabilities.	3,317	-	3,317
TOTAL CAPITALIZATION AND LIABILITIES	$345,398	$308,524	$316,608

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 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 months and account for 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 March 31, 2001 and 2000, there was deferred revenue of $7.2 million. These deferred revenues are accreted into revenue throughout the current year. Seasonal rates will be eliminated in April 2001, which is expected to generate approximately $6.0 million in additional cash flow in 2001 that can be used to offset increased costs during 2001, 2002 and 2003. See the discussion under "Commitments and Contingencies - Retail Rate Cases" for further information.

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", 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 report 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 subsidiaries (excluding NWR) and the rental water heater program are included 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")
Percent ownership: 17.9% common

	Three months ended March 31	
	2001	2000
(in thousands)		
Gross Revenue.	$40,964	$40,692
Net Income Applicable. to Common Stock	1,550	1,744
Equity in Net Income .	273	314

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

If the plant is auctioned, then the Company would continue equity ownership of VY until sold, and would enter into a power supply agreement with the new plant owners.

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

Percent ownership: 29.5% 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.

(in thousands)	Three months ended March 31 2001	2000
Gross Revenue	$7,170	$6,715
Net Income.	243	273
Equity in Net Income.	55	84

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("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 March 31, 2001, our total expenditures related to the Pine Street site since 1982 were approximately $23.9 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 $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 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

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 contains the following provisions:

* The Company receives 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 are 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 agrees not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;
* The Company 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 will be eliminated in April 2001, which is expected to

generate approximately $6.0 million in additional cash flow in 2001 that can be utilized to offset potential increased costs during 2001, 2002 and 2003;

* The Company agrees to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making; and
* The Company agrees to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the Company's 1997 rate case.

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

* The VPSB Order requires the Company and its customers to share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share; 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 or called to purchase 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, and is recognized ratably over 2001. The Company recognized $1.7 million in expense during the quarter ended March 31, 2001 to reflect these estimated costs. A regulatory asset of $4.9 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 and/or amounts previously recorded, the excess cost would be immediately charged against earnings. No charge for excess cost was required during the first quarter of 2001. The Company has purchased power sufficient to fulfill the 9701 option calls for this summer, and no charges in excess of amounts provided in rates or previously recorded are anticipated for the remainder of 2001.

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

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 months ended March 31, 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 million higher for the three months ended March 31, 2000.

POWER SUPPLY AND TRANSMISSION

Company-owned generation expenses increased $1.2 million in the first quarter of 2001 compared with the same period in 2000 primarily due to the higher cost of fuels and the unavailability of unique replacement equipment connecting Vermont's transmission system to that of New York. The lack of such equipment required running generation to support system reliability. The Company has requested reimbursement of its costs of running its units for system reliability from the Independent System Operator of New England ("ISO"). The Company recorded a regulatory asset and reduced Company-owned generation expense by $1.0 million, representing incremental fuel and operation and maintenance costs due from ISO. If the ISO were to reject a portion of the Company's costs, the Company believes it could recover these costs from ratepayers under the Settlement Order.

A FERC ruling in December 2000 required 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 a large cost impact. As a result, the $0.17 per kW month charge was reinstated from August 1, 2000 until April 1, 2001. The 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.

On March 16, 2001, an ISO participant filed a request for re-hearing the FERC's March 6, 2001 Order on Rehearing. The request asks for a reversal of the lowered ICAP charge for the period from August 1, 2000 until April 1, 2001. If the lowered ICAP charge is increased to $8.75 per kw month for the period from August 1, 2000 to March 31, 2001, then the Company would be required to pay ISO approximately $1.4 million. Also, 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 U.S. Court of Appeals for the First Circuit in Boston is tentatively scheduled to hear oral arguments from the utilities and FERC on May 8, 2001, according to the court order. Management cannot determine the ultimate impact of these actions at this time.

The Company has purchased ICAP associated with 2001 obligations for its 9701 arrangement with Hydro-Quebec at an average price of approximately $4 per MWh. The Company has also arranged to purchase 50 percent of its anticipated 9701 ICAP needs during 2002 at an average cost of $2.60 per MWh.

As of March 31, 2001, the Company had deferred a total of $4.6 million, its share of arbitration costs related to the pursuit of claims against Hydro-Quebec arising from its suspension of deliveries during and after the 1998 ice storm. The Company has received an accounting order from the VPSB providing for the deferral of these charges, subject to final determination in a future rate proceeding.

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 split decision, (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. Any proceeds ultimately received would reduce related deferred assets. We believe it is probable that the arbitration costs, should they exceed any recovery from the arbitration decision, 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. The provisions for loss from discontinued operations reflect the Company's most recent estimate. The ultimate loss remains subject to the consummation of the sale or other disposition of NWR's remaining assets and liabilities, primarily waste-water treatment projects, 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 March 31	
	2001	2000
In thousands, except per share data		
External revenues		
Electric utility.	$74,796	$67,712
NWR segment	35	97
Net income (loss) from operations		
Electric utility.	$ 2,914	$ 3,449
NWR segment	-	-
Consolidated net income (loss) . . .	$ 2,914	$ 3,449
Basic earnings (loss) per share		
Discontinued operations	$ -	$ -
Continuing operations	0.52	0.63
Diluted earnings per share		
Discontinued operations	-	-
Continuing operations	$ 0.51	$ 0.63

5. NEW ACCOUNTING STANDARD - SFAS 133

In June 1998, the Financial Accounting Standards Board 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 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 future contracts (derivatives) to hedge forecasted wholesale 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 allows 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 March 31, 2001, the Company had a regulatory asset of approximately $31.5 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. 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 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 March 31	
	2001	2000
In thousands		
Net income.	$2,914	$3,449
Preferred stock dividend requirement. .	235	270
Net income applicable to common stock.	$3,149	$3,719
Average number of common shares-basic .	5,588	5,437
Dilutive effect of stock options. . . .	153	-
Anti-dilutive stock options	-	-
Average number of common shares-diluted	5,741	5,437

GREEN MOUNTAIN POWER CORPORATION
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
MARCH 31, 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 March 31	
	2001	2000

Utility business . . .	$0.50	$0.60
Unregulated businesses	0.02	0.03
Earnings(loss) from: . Continuing operations	0.52	0.63
Discontinued segment .	0.00	0.00
Basic earnings (loss) per share . .	$0.52	$0.63

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of $0.50 in the quarter ended March 31, 2001, compared with utility earnings of $0.60 per share in the first quarter of 2000. Increased retail revenues resulting from a 3.42 percent rate increase approved by the Vermont Public Service Board ("VPSB") on January 23, 2001 (the "Settlement Order") were more than offset by higher power supply costs to serve customers.
The Company has previously accrued losses for disallowed Hydro-Quebec power supply costs pursuant to VPSB orders. Results for the three months ended March 31, 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 million higher for the three months ended March 31, 2000. Power supply costs were also higher in the first quarter of 2001 due to increased regional energy prices, reduced availability of some Company hydroelectric generation capacity, energy purchases to cover potential shortages due to transmission system operating requirements, and scheduled increases in our long-term power supply contract with MS.

UNREGULATED BUSINESSES

Earnings from unregulated businesses included in results from continuing operations for the three months ended March 31, 2001 were slightly lower than during the same period in 2000. A financial summary for these businesses, excluding NWR, follows:

In thousands	Three months ended March 31 2001	2000
Revenue. . .	$ 259	$ 262
Expense. . .	125	125
Net Income .	$ 134	$ 137

===== =====

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's operating loss for the three months ended March 31, 2001 has been previously recognized as provision for operating loss during phase-out period. The ultimate loss remains subject to the sale or other disposition of NWR's remaining assets and liabilities, primarily waste-water treatment projects, and could exceed amounts recorded. Most of NWR's energy generation and energy efficiency assets have been sold. The operating loss for the three months ended March 31, 2001 would have been approximately $486,000 compared with a loss of $879,000 for the same period a year ago.

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatthour ("MWh") sales and average number of customers for the three months ended March 31, 2001 and 2000 are summarized below:

	Three months ended March 31	
	2001	2000
(dollars in thousands)		
Operating revenues		
Retail.	$ 51,953	$ 49,550
Sales for Resale. . .	21,838	17,300
Other	1,005	862
Total Operating Revenues.	$ 74,796	$ 67,712
MWh sales-Retail.	520,771	520,222
MWh sales for Resale. . .	638,096	567,685
Total MWh Sales	1,158,867	1,087,907

	Average Number of Customers Three months ended March 31	
	2001	2000
Residential	73,149	72,165
Commercial and Industrial	12,933	12,574
Other	65	64

Total Number of Customers. .	86,147	84,803
	======	======

REVENUES

Revenues from operations in the first quarter of 2001 increased 10.5 percent or $7.1 million compared with the same period in 2000. Operating revenues result from retail and wholesale sales of electricity.

Retail revenues in the first quarter of 2001 were $2.4 million or 4.8 percent higher compared with the same period in 2000, reflecting a 3.42 percent rate increase effective January 2001, and a 0.1 percent increase in retail MWh sales. Sales of electricity increased by 1.6 percent to small commercial and industrial customers, and decreased by 2.0 percent to residential customers and 1.1 percent to lower margin industrial customers during the first quarter of 2001 compared with the same period in 2000.

We sell wholesale electricity to others for resale. Our revenue from wholesale sales of electricity increased $4.5 million in the first quarter of 2001 compared with the same period in 2000. The increase was due primarily to increased sales under a power purchase and supply agreement between the Company and MS, and increased 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.

OPERATING EXPENSES

POWER SUPPLY EXPENSES - THREE MONTHS ENDED MARCH 31, 2001

Power supply expenses increased 18.6 percent or $8.5 million in the first quarter of 2001 over the same period in 2000.

Power supply expenses at Vermont Yankee ("VY") decreased 0.2% or $16,000 during the first quarter of 2001 compared with the first quarter of 2000. A proposed sale of the generating plant is discussed under Part I, Item 2, "Investment in Associated Companies".

Company-owned generation expenses increased $1.2 million in the first quarter of 2001 compared with the same period in 2000 primarily due to the higher cost of fuels and the unavailability of unique replacement equipment connecting Vermont's transmission system to that of New York. The lack of replacement equipment required running generation to support system reliability. The Company has requested reimbursement of its costs of running its units for system reliability from the Independent System Operator of New England ("ISO"). The Company recorded a regulatory asset and reduced Company-owned generation expense by $1.0 million, representing incremental fuel and operation and maintenance costs due from ISO.

The cost of power that we purchased from other companies increased 16.5 percent or $7.4 million in the first quarter of 2001 compared with the same period in 2000. This was primarily due to power supply costs for increased wholesale electric sales of $4.5 million to replace power sold to Hydro-Quebec under a previous arrangement ("9701"), to buy energy that could potentially have been curtailed due to transmission system operating requirements, and for power sold to MS under the power purchase and supply agreement.

Power supply costs were also higher during the first quarter of 2001 compared with the same period in 2000 due to higher energy clearing prices in the New England market, the unavailability of hydroelectric capacity that is estimated to have cost the Company an additional $850,000, and scheduled increases in the cost of power under our long-term contract with MS.

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 of replacing power purchased by Hydro-Quebec of approximately $6.6 million annually. The Company recognized $1.7 million in expense during the quarter ended March 31, 2001 to reflect these estimated costs. A regulatory asset of $4.9 million was established for the remaining estimated difference between the option exercise price and the expected cost of replacement power for 2000 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 quarter of 2001. The Company has 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 the 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 March 31, 2001, the Company had a regulatory asset of approximately $31.5 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 decreased 7.2 percent or $259,000 in the first quarter of 2001 compared with the same period in 2000. The reduction reflects decreased amortization due to the write-off of state regulatory commission costs coincident with the Settlement Order.

TRANSMISSION EXPENSES

Transmission expenses decreased by approximately $24,000 or 0.7% for the three months ended March 31, 2001 compared with the same period in 2000. Congestion charges recorded in the first quarter 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 decreased $478,000 or 11.5 percent during the first quarter of 2001 compared with the same period in 2000. The reduction is primarily due to decreased amortization of demand side management assets.

TAXES OTHER THAN INCOME TAXES

Other taxes decreased 1.9 percent or $39,000 in the first quarter of 2001 compared with the same period in 2000, reflecting payroll tax decreases that were partially offset by gross revenue tax increases.

INCOME TAXES

Income taxes decreased $435,000 in the first quarter of 2001 compared with the same period in 2000 due to a decrease in pretax book income for core electric operations.

OTHER INCOME

Other income for the three months ended March 31, 2001 decreased approximately $334,000 or 38.3 percent compared with the same period in 2000 due primarily to decreases in capitalized interest costs and decreased earnings from subsidiaries.

INTEREST CHARGES

Interest charges increased 11.24 percent or $198,000 in the first quarter of 2001 over the same period in 2000 primarily due to costs associated with the revolving lines of credit discussed under "Liquidity and Capital Resources".

LIQUIDITY AND CAPITAL RESOURCES

In the three months ended March 31, 2001, we spent $2.8 million principally for expansion and improvements of our transmission and distribution plant. We expect to spend an additional $13.0 million during the remainder of 2001.

On June 21, 2000, we renewed a revolving credit agreement with Fleet National Bank and Citizens Bank of Massachusetts (the "Fleet Agreement"). The Fleet Agreement is for a period of 364 days, will expire on June 20, 2001, and is secured by granting the banks a second priority mortgage, lien and security interest in the collateral pledged under the Company's first mortgage bond indenture. We had no borrowings outstanding on the Fleet Agreement at March 31, 2001.

On September 20, 2000, we established a $15.0 million revolving credit agreement with KeyBank National Association ("KeyBank"). The agreement will expire on September 19, 2001. Pursuant to a one year power supply option agreement between the Company and Energy East Corporation ("EE"), EE made a payment of $15.0 million to the Company. In exchange, the Company gave EE an option to purchase energy from certain wholly owned production facilities, for a period not to exceed 15 years, if the funds are not returned to EE upon request after September 2001. The Company was required to invest the funds provided by EE in a certificate of deposit at KeyBank pledged by the Company to secure the repayment of the Keybank revolving credit facility. At March 31, 2001, there was $8.9 million outstanding on the KeyBank revolving credit agreement.

The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2001 and that amounts financed will be sufficient to meet our forecasted borrowing requirements during 2001.

The credit ratings of the Company's securities are:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB	Baa2	BBB
Preferred stock	BBB-	baa3	BB

During the first quarter of 2001, Moody's Investors Service and Fitch upgraded the Company's first mortgage bond and preferred stock ratings. The rating actions reflected the rating agencies' earnings and cash flow expectations for the Company following the Settlement Order. Standard & Poor's has favorably changed its outlook, which already rated the first mortgage bonds at investment grade, relative to the ratings direction for the Company.

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 among and within various regions of the country;
* Improvements in generation efficiency;
* Alternative energy sources;

* Increasing demand for customer choice;
* The deregulation of the energy market and the establishment of an independent system operator; and
* The contemplated restructuring of the Vermont electric industry to introduce competition.

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 had agreed to review the accounting for closure and removal costs, including decommissioning. We do not believe that changes in such accounting, if required, would have an adverse effect on the results of operations due to our current and future ability to recover decommissioning costs through rates.

EFFECTS OF INFLATION

Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This 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

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 the table.

	At March 31, 2001 Fair value	Market risk
	In thousands	
Highest long position .	$ 86,993	$ 8,699
Highest short position.	$ 116,841	$ 11,684
Average position(short)	$ (29,848)	$ (2,985)

PART II

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

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

April 17, 2001 Form 8-K announced the decision reached by the arbitration tribunal in the Company's arbitration with Hydro-Quebec regarding ice-storm related delivery failure. The arbitration tribunal decided 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 Hydro-Quebec is required to return certain capacity payments to the Company.

May 1, 2001 Form 8-K announced the upgrade in credit rating by Fitch. Fitch upgraded credit ratings for the company's first mortgage bonds from BB+ to BBB, and preferred stock from B+ to BBB- following the favorable rate order approved by the VPSB in January 2001.

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: May 10, 2001

/s/ NANCY ROWDEN BROCK
Nancy Rowden Brock, Vice President, Chief Financial Officer, Secretary, and Treasurer

Date: May 10, 2001

/s/ROBERT J. GRIFFIN
Robert J. Griffin, Controller