GREEN MOUNTAIN POWER CORP
Form 10-Q
August 14, 2002

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2002

OR

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

COMMISSION FILE NUMBER 1-8291

GREEN MOUNTAIN POWER CORPORATION
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

VERMONT 03-0127430

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

163 ACORN LANE
COLCHESTER, VT 05446

ADDRESS OF PRINCIPAL EXECUTIVE OFFICES (ZIP CODE)

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

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

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

CLASS - COMMON STOCK	OUTSTANDING AT AUGUST 9, 2002
$3.33 1/3 PAR VALUE	5,723,540

GREEN MOUNTAIN POWER CORPORATION
INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30,
2002 AND 2001

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED COMPARATIVE INCOME STATEMENTS

UNAUDITED

	THREE MONTHS ENDED JUNE 30		SIX MONTHS JUNE 30	
In thousands, except per share data	2002	2001	2002	2
OPERATING REVENUES	$65,135	$67,471	$134,001	$14
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation.	8,191	5,737	16,265	1
Company-owned generation.	617	(133)	1,578	
Purchases from others	37,588	40,166	75,734	7
Other operating.	3,547	4,405	7,054	
Transmission	4,002	3,544	7,972	
Maintenance.	2,059	2,078	4,274	
Depreciation and amortization.	3,408	3,623	6,939	
Taxes other than income.	1,934	1,915	3,905	
Income taxes	975	1,861	3,025	

Total operating expenses	62,321	63,196	126,746	13
OPERATING INCOME	2,814	4,275	7,255	
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations	535	584	1,069	
Allowance for equity funds used during construction	49	45	122	
Other income (deductions), net	15	(47)	(53)	
TOTAL OTHER INCOME (DEDUCTIONS)	599	582	1,138	
INCOME BEFORE INTEREST CHARGES	3,413	4,857	8,393	
INTEREST CHARGES				
Long-term debt	1,254	1,547	2,613	
Other interest	295	232	508	
Allowance for borrowed funds used during construction	(22)	(41)	(54)	
TOTAL INTEREST CHARGES	1,527	1,738	3,067	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	1,886	3,119	5,326	
Preferred stock dividend requirement	11	235	95	
Income from continuing operations	1,875	2,884	5,231	
Net income from discontinued segment operations	-			
Loss on disposal, including provisions for operating losses during phaseout period	-	(150)	-	
NET INCOME APPLICABLE TO COMMON STOCK	$ 1,875	$ 2,734	$ 5,231	$
Common stock data				
Basic earnings per share	$ 0.33	$ 0.49	$ 0.92	$
Diluted earnings per share	0.32	0.47	0.89	
Cash dividends declared per share	$ 0.14	$ 0.14	$ 0.28	$
Weighted average common shares outstanding-basic	5,711	5,615	5,701	
Weighted average common shares outstanding-diluted	5,877	5,777	5,866	
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS				
Balance - beginning of period	$10,644	$ 2,639	$ 8,070	$
Net Income	1,886	2,969	5,326	
Preferred stock dividend requirement	(11)	(235)	(95)	
Other	(50)	-	(50)	
Cash Dividends-common stock	(786)	(771)	(1,568)	(
Balance - end of period	$11,683	$ 4,602	$ 11,683	$

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

GREEN MOUNTAIN POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

OPERATING ACTIVITIES:

Net income before preferred stock dividend requirement
Adjustments to reconcile net income to net cash
provided by operating activities:
Depreciation and amortization
Dividends from associated companies less equity income
Allowance for funds used during construction
Amortization of purchased power costs
Deferred income taxes
Deferred revenues
Deferred purchased power costs
Accrued purchase power contract option call
Earnings cap deferral and rate levelization liability
Environmental and conservation amortization (deferrals), net
Changes in:
Accounts receivable
Accrued utility revenues
Fuel, materials and supplies
Prepayments and other current assets
Accounts payable
Accrued income taxes payable and receivable
Other current liabilities
Other

Net cash provided by continuing operations

INVESTING ACTIVITIES:
Construction expenditures
Investment in nonutility property

Net cash used in investing activities

FINANCING ACTIVITIES:
Redemption of preferred stock
Issuance of common stock
Reduction in long term debt
Power supply option obligation, net
Short-term debt, net
Cash dividends and preferred stock dividend requirement

Net cash used in financing activities

Net increase(decrease) in cash and cash equivalents

Cash and cash equivalents at beginning of period

Cash and cash equivalents at end of period

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:
Cash paid year-to-date for:
Interest (net of amounts capitalize
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 JUNE 30, 2002	2001
		In thousands	
ASSETS			
UTILITY PLANT			
Utility plant, at original cost		$ 306,127	$295,133
Less accumulated depreciation		122,950	114,380
Net utility plant		183,177	180,753
Property under capital lease		5,959	6,449
Construction work in progress		10,530	6,955
	Total utility plant, net	199,666	194,157
OTHER INVESTMENTS			
Associated companies, at equity		14,019	14,322
Other investments		7,108	6,598
	Total other investments	21,127	20,920
CURRENT ASSETS			
Cash and cash equivalents		21	11
Certficate of deposit, pledged as collateral		-	15,936
Accounts receivable, customers and others, less allowance for doubtful accounts	of $613, $613, and $613	15,902	24,560
Accrued utility revenues		5,015	6,385
Fuel, materials and supplies, at average cost		3,885	4,316
Prepayments		413	889
Income tax receivable		-	-
Other		363	278
	Total current assets	25,599	52,375
DEFERRED CHARGES			
Demand side management programs		6,687	6,485
Purchased power costs		1,995	8,604
Pine Street Barge Canal		12,425	12,370
Power supply derivative deferral		33,694	15,714
Other		14,612	15,749
	Total deferred charges	69,413	58,922
NON-UTILITY			
Cash and cash equivalents		-	-
Other current assets		8	8
Property and equipment		250	251

Other assets	775	847
Total non-utility assets	1,033	1,106
TOTAL ASSETS	$ 316,838	$327,480

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

	UNAUDITED AT JUNE 30, 2002	200
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 5,716,975, 5,641,009 and 5,701,010)	$ 19,110	$ 18,
Additional paid-in capital	74,948	73,
Retained earnings	11,683	4,
Treasury stock, at cost (15,856 shares)	(378)	(
Total common stock equity	105,363	96,
Redeemable cumulative preferred stock	85	12,
Long-term debt, less current maturities	71,000	70,
Total capitalization	176,448	179,
CAPITAL LEASE OBLIGATION	5,959	6,
CURRENT LIABILITIES		
Current maturities of preferred stock	150	
Current maturities of long-term debt	8,000	9,
Short-term debt	10,400	4,
Accounts payable, trade and accrued liabilities	6,410	8,
Accounts payable to associated companies	6,825	5,
Accrued taxes	933	
Customer deposits	838	
Purchased power call option liability	-	5,
Interest accrued	1,145	1,
Energy East power supply obligation	-	16,
Rate Levelization liability	4,218	4,
Deferred revenues	-	3,
Other	1,081	1,
Total current liabilities	40,000	63,
DEFERRED CREDITS		
Power supply derivative liability	33,694	15,

Accumulated deferred income taxes		24,888	24,
Unamortized investment tax credits		3,272	3,
Pine Street Barge Canal site cleanup		9,436	11,
Other		20,787	21,
	Total deferred credits	92,077	75,
COMMITMENTS AND CONTINGENCIES			
NON-UTILITY			
Other Liabilities		2,354	1,
	Total non-utility liabilities	2,354	1,
TOTAL CAPITALIZATION AND LIABILITIES		$316,838	$327,

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

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

PART I-ITEM 1

1. SIGNIFICANT ACCOUNTING POLICIES

It is our opinion that the financial information contained in this report reflects all normal, recurring adjustments necessary to present a fair statement of results for the period reported, but such results are not necessarily indicative of results to be expected for the year due to the seasonal nature of our business and include other adjustments discussed elsewhere in this report necessary to reflect fairly the results of the interim periods. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. However, the disclosures herein, when read with the annual report for 2001 filed on Form 10-K, are adequate to make the information presented not misleading.

The Vermont Public Service Board ("VPSB"), the regulatory commission in Vermont, sets the rates we charge our customers for their electricity. In periods prior to April 2001, we charged our customers higher rates for billing cycles in December through March and lower rates for the remaining months. These were called seasonally differentiated rates. Seasonal rates were eliminated in April 2001, and generated approximately $8.5 million of revenues deferred in 2001 that we estimate will be used to offset increased costs during 2002, including $2.2 million that was recognized during the first quarter, and $2.1 million recognized in the second quarter.

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

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

UNREGULATED OPERATIONS

We have or have had unregulated, wholly owned subsidiaries: Northern Water

Resources, Inc. ("NWR"); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; and Green Mountain Resources, Inc. ("GMRI"). During 2000 and 2001, we sold most of the assets of NWR, 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 subsidiaries, including NWR during 2002, and the rental water heater program are included in equity in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Comparative Income Statements.

2. INVESTMENT IN ASSOCIATED COMPANIES

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

VERMONT YANKEE NUCLEAR POWER CORPORATION ("VY", OR "VERMONT YANKEE")
Percent ownership: 19.0% common

	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	2002	2001
(in thousands)				
Gross Revenue.	$46,764	$57,031	$85,495	$97,995
Net Income Applicable. to Common Stock	1,462	1,574	2,949	3,124
Equity in Net Income .	258	287	571	560

On August 15, 2001, VY agreed to sell its nuclear power plant to Entergy Corporation for approximately $180 million. On July 31, 2002, Vermont Yankee announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("Entergy") had been completed. In addition to the sale of the generating plant, the transaction calls for Entergy to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company's energy requirements. The Company continues to own approximately 19 percent of the common stock of VY. The benefits to Green Mountain Power of the plant sale and power contract with Entergy include:

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

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

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

Prices under the power contract with Entergy range from $39 to $45 per megawatt-hour, substantially lower than the forecasted cost of continued ownership and operation by Vermont Yankee.

The power contract with Entergy calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, the contract prices are not adjusted upward.

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

The VY plant had fuel rods that required repair during May 2002, a maintenance requirement that is not unique to VY. VY shutdown the plant for a twelve-day period, beginning on May 11, 2002, to repair the rods. The Company estimates its portion of the cost for repair, including incremental replacement energy costs, to be approximately $2.0 million. The Company received an accounting order from the Vermont Public Service Board on August 2, 2002, allowing it to defer the additional costs related to the outage, and believes that such amounts are probable of future recovery.

The Company's ownership share of VY has increased from approximately 17.9 percent last year to approximately 19.0 percent currently, due to VY's purchase of certain minority shareholders' interests.

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.

	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	2002	2001
(in thousands)				
Gross Revenue	$5,312	$8,548	$11,796	$15,718
Net Income.	318	309	513	552
Equity in Net Income.	92	91	169	146

3. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL MATTERS

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements and that there are no outstanding material complaints about the Company's compliance with present environmental protection regulations, except for developments related to the Pine Street Barge Canal site.

PINE STREET BARGE CANAL SITE

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

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

As of June 30, 2002, our total expenditures related to the Pine Street site since 1982 were approximately $25.9 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 waiting further VPSB action. The bulk of these expenditures consisted of transaction costs. Transaction costs include legal and consulting costs associated with the Company's opposition to the EPA's earlier proposals of a more expensive remedy at the site, litigation and related costs necessary to obtain settlements with insurers and other PRPs to provide amounts required to fund the clean up ("remediation costs"), and to address liability claims at the site. A smaller amount of past expenditures was for site-related response costs, including costs incurred pursuant to EPA and State orders that resulted in funding response activities at the site, and to reimbursing the EPA and the State for oversight and related response costs. The EPA and the State have asserted and affirmed that all costs related to these orders are appropriate costs of response under CERCLA for which the Company and other PRPs were legally responsible.

We estimate that we have recovered or secured, or will recover, through settlements of litigation claims against insurers and other parties, amounts that exceed estimated future remediation costs, future federal and state government oversight costs and past EPA response costs. We currently estimate our unrecovered transaction costs mentioned above, which were necessary to recover settlements sufficient to remediate the site, to oppose much more costly solutions proposed by the EPA, and to resolve monetary claims of the EPA and the State, together with our remediation costs, to be $12.4 million 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 Vermont Department of Public Service (the "Department"), and as applicable, other parties, reached agreements in these cases that the full amount of the site-related costs reflected in those rate cases should be recovered in rates.

We proposed in our rate filing made on June 16, 1997 recovery of an additional $3.0 million in such expenditures. In an Order in that case released March 2, 1998, the VPSB suspended the amortization of expenditures associated with the Pine Street site pending further proceedings. Although it did not eliminate the rate base deferral of these expenditures, or make any specific order in this regard, the VPSB indicated that it was inclined to agree with other parties in the case that the ultimate costs associated with the Pine Street site, taking into account recoveries from insurance carriers and other PRPs, should be shared between customers and shareholders of the Company. In response to our Motion for Reconsideration, the VPSB on June 8, 1998 stated its intent was "to reserve for a future docket issues pertaining to the sharing of remediation-related costs between the Company and its customers". The VPSB Order released January 23, 2001 and discussed below did not change the status of Pine Street cost recovery.

RETAIL RATE CASE

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

* The Company received a rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases became permanent;
* Rates were set at levels that recover the Company's Hydro-Quebec VJO contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;
* The Company agreed not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain

substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels;

* The Company agreed to write off in 2000 approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing;
* Seasonal rates were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003;
* The Company agreed to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making;
* The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in a 1997 rate case; and
* The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets. The Company earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount.

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

* The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share; and
* The Company's further investment in non-utility operations is restricted.

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 half of 2002, $1.5 million in power supply expense was recognized to reflect the cost of option A, which is recognized ratably over the year. Hydro-Quebec has previously agreed not to call option B during the 2002 contract year. At June 30, 2002, the cumulative amount of power purchased by Hydro-Quebec under option B is approximately 432,000 MWh.

During the first quarter of 2001, Hydro-Quebec exercised option A and option B, calling for deliveries of 134,592 MWh during June, July and August of 2001. The Company recognized $3.3 million in expense during the six months ended June 30, 2001 to reflect 9701 estimated costs. A regulatory asset of $3.3 million was established for the remaining estimated difference between the option exercise price and the expected cost of replacement power for 2001.

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

Hydro-Quebec's option to curtail energy deliveries pursuant to a July 1994 Agreement can be exercised in addition to these purchase options if documented drought conditions exist. The exercise of this curtailment option is limited to five times, requiring notice four months in advance of any contract year, and cannot reduce deliveries by more than approximately 13 percent. The Company may defer the curtailment by one year. Hydro-Quebec also has the option to reduce the load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. The Company can delay the load factor reduction by one year under the same contract. During 2001, Hydro-Quebec exercised the first of its load factor reduction options intended for 2002, and the Company delayed the effective date of this exercise until 2003. The Company estimates that the net cost of Hydro-Quebec's exercise of its load factor reduction option will increase power supply expense during 2003 by approximately $0.4 million.

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

COMPETITION

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. In March 2002, voters in Rockingham authorized Rockingham to create a municipal utility by acquiring a municipal plant, which would include the Bellows Falls hydroelectric facility and the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that our remaining customers do not subsidize a Rockingham municipal utility.

4. SEGMENTS AND RELATED INFORMATION

The Company has two reportable segments during 2002, the electric utility and NWR. NWR was reported as discontinued operations in 2001. The Company was unable to sell all of the NWR investments and believes that classification and reporting as discontinued operations is no longer appropriate. The electric utility is engaged in the distribution and sale of electrical energy in the State of Vermont and also reports the results of its wholly owned unregulated subsidiaries (GMPG, GMRI, NWR and GMP Real Estate) and the rental water heater program as a separate line item in the Other Income section in the Consolidated Statement of Income.

NWR is an unregulated business that invested in energy generation, energy efficiency and wastewater treatment projects. As of June 30, 2002, most of NWR's net assets and liabilities have been sold or otherwise disposed. The remaining net liability reflects expected warranty obligations, net of equity investments in two wind farms and wastewater treatment projects.

In 2001, the Company reported NWR results as discontinued operations. The provisions for loss from discontinued operations reflected the Company's most recent estimate at that time. The ultimate loss remains subject to the disposition of NWR's remaining liabilities, primarily wastewater treatment warranty obligations, and could exceed amounts recorded. Results of operations for NWR for the three and six months ended June 30, 2002 are now reported as continuing operations under the caption Equity in earnings of affiliates and non-utility operations. Segment information compared with the Company's results includes the following:

	Three months ended June 30		Six months ended June 30	
	2002	2001	2002	2001

(in thousands, except per share data)

External revenues				
Electric utility	$65,135	$74,796	$134,001	$142,267
NWR segment.	62	35	62	104
Net income from operations				
Electric utility	$ 1,890	$ 2,884	$ 5,272	$ 5,798
NWR segment.	(15)	(150)	(41)	(150)
Consolidated net income	$ 1,875	$ 2,914	$ 5,231	$ 5,648
Basic earnings per share				
Discontinued operations.	$ -	$ (0.03)	$ -	$ (0.03)
Continuing operations.	0.33	0.51	0.92	1.04
Diluted earnings per share				
Discontinued operations.	$ -	$ (0.03)	$ -	$ (0.03)
Continuing operations.	0.32	0.47	0.89	0.98

5. DERIVATIVE INSTRUMENTS AND RISK MANAGEMENT

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

SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS 133, as amended by SFAS 137, was effective for the Company beginning 2001.

One objective of the Company's risk management program is to stabilize cash flow and earnings by minimizing power supply risks. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights with counter-parties that have at least investment grade ratings. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Futures, swaps and forward contracts are used to hedge market prices should option calls by Hydro-Quebec be exercised. The Company's risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings effects relating to future periods caused by application of SFAS 133. At June 30, 2002, the Company had a liability reflecting the fair value of the two derivatives described below, as well as a corresponding regulatory asset of approximately $33.7 million. The Company believes that the regulatory asset is probable of recovery in future rates. The liability is based on current estimates of future market prices that are subject to change by material amounts.

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

The Company has a contract with Morgan Stanley Capital Group, Inc. ("MS") used to hedge against increases in fossil fuel prices. MS purchases the majority of the Company's power supply resources at index (fossil fuel resources) or specified (i.e., contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The MS contract is a derivative under SFAS 133 and was scheduled to expire on December 31, 2003. In August

2002, the Company extended the contract with MS through December 31, 2006. Beginning in 2004, the extended contract includes only our interests in the Wyman and Stonybrook plants with respective capacities of 7 MW and 45 MW, and our estimated load requirements not satisfied by contractual arrangements and other owned generation. The cost of power purchased from MS for 2003 is expected to be approximately $6.0 million less than the cost of power purchased from MS during 2002. The remainder of our load requirements are substantially provided through our power supply contracts and arrangements with Hydro-Quebec and our entitlements to power generated at the Vermont Yankee nuclear plant now owned by Entergy.

Management's estimate of the fair value of the future net cost of this contract at June 30, 2002 is approximately $5.1 million.

We also sometimes use future contracts to hedge forecasted wholesale sales of electric power, including material sales commitments. We currently have an arrangement with Hydro-Quebec that grants it an option to call power at prices below current and estimated future market rates. This arrangement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this arrangement at June 30, 2002 is approximately $28.6 million.

6. NEW ACCOUNTING STANDARDS

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

In 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), effective for the Company's 2003 fiscal year, which provides guidance on accounting for nuclear plant decommissioning costs. SFAS 143 prescribes fair value accounting for asset retirement liabilities, including nuclear decommissioning obligations, and requires recognition of such liabilities at the time incurred. The Company has not yet determined what impact, if any, the accounting standard will have on its financial position or results of operations.

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

7. COMPUTATION OF EARNINGS PER SHARE

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

	Three months ended June 30		Six months ended June 30	
	2002	2001	2002	2001
(in thousands)				
Net income before preferred dividends. .	$1,886	$2,969	$5,326	$6,117

Preferred stock dividend requirement . .	11	235	95	469
Net income applicable to common stock. .	$1,875	$2,734	$5,231	$5,648
Average number of common shares-basic. .	5,711	5,615	5,701	5,602
Dilutive effect of stock options	166	162	165	157
Anti-dilutive stock options.	-	-	-	-
Average number of common shares-diluted.	5,877	5,777	5,866	5,759

GREEN MOUNTAIN POWER CORPORATION
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL
CONDITION AND RESULTS OF OPERATIONS
JUNE 30, 2002

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.

Management believes the most critical accounting policies include the regulatory accounting framework within which we operate and the manner in which we account for certain power supply arrangements that qualify as derivatives. These accounting policies, among others, affect the Company's more significant judgments and estimates used in the preparation of its consolidated financial statements, including estimates and judgments used in determining the current period recognition of revenues deferred in 2001, as discussed further under the caption "Operating Revenues and MWh Sales-Revenues", in this section.

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

There are statements in this section that contain projections or estimates and are considered to be "forward-looking" as defined by the Securities and Exchange Commission. In these statements, you may find words such as "believes," "estimates", "expects," "plans," or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be materially different from those projected. Some of the reasons the results may be different are listed below and are discussed under "Competition and Restructuring" in this section:

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

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

RESULTS OF OPERATIONS

EARNINGS SUMMARY - OVERVIEW

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

Total basic earnings per share of Common Stock*

	Three months ended June 30		Six months ended June 30	
	2002	2001	2002	2001
Utility business	$0.31	$ 0.51	$0.89	$ 0.99
Unregulated businesses .	0.02	0.01	0.03	0.05
Earnings from:				
Continuing operations. .	0.33	0.52	0.92	1.04
Discontinued segment . .	-	(0.03)	-	(0.03)
Basic earnings per share	$0.33	$ 0.49	$0.92	$ 1.01

*The three and six months ended June 30, 2002 include recognition of $2.1 million and
$4.2 million of deferred revenues, respectively

UTILITY BUSINESS

The Company recorded basic earnings per share from utility operations of $0.31 in the quarter ended June 30, 2002, compared with utility earnings of $0.51 per share in the second quarter of 2001. Earnings declined as a result of increased power supply costs during the second quarter of 2002, compared with the same quarter of 2001. Power supply costs rose as a result of increased costs under our power supply agreement with Morgan Stanley, capacity cost increases at the Vermont Yankee nuclear plant and reimbursement of approximately $1.0 million received in 2001 for power supply costs incurred during previous periods. The increases in power supply costs in the second quarter of 2002 were partially offset by a reduction in costs arising from decreased sales of electricity to wholesale customers.

Retail operating revenues increased by $2.7 million during the second quarter of 2002, compared with the same quarter of 2001, primarily due to the recognition of $2.1 million in revenues deferred during 2001 in accordance with the settlement of the Company's retail rate case approved by the Vermont Public Service Board in January 2001.

Basic earnings per share from utility operations for the six months ended June 30, 2002 were $0.89 compared with basic earnings per share of $0.99 for the same period in 2001, due to the same factors influencing second quarter results.

UNREGULATED BUSINESSES

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

Three Months Ended June 30	Six Months Ended June 30

	2002	2001	2002	2001
	In thousands			
Revenue. .	$ 253	$ 251	$ 502	$ 510
Expense. .	150	131	$ 316	256
Net Income	$ 103	$ 120	$ 186	$ 254

OPERATING REVENUES AND MWH SALES

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

	Three months ended June 30		Six months ended June 30	
	2002	2001	2002	2001
(dollars in thousands)				
Operating revenues				
Retail.	$ 48,256	$ 45,586	$ 100,745	$ 97,539
Sales for Resale. . .	16,092	20,760	31,901	42,598
Other	787	1,126	1,355	2,131
Total Operating Revenues.	$ 65,135	$ 67,472	$ 134,001	$ 142,268
MWh sales-Retail.	457,128	459,144	952,622	977,405
MWh sales for Resale. . .	517,937	545,288	1,036,224	1,183,384
Total MWh Sales	975,065	1,004,432	1,988,846	2,160,789

Average Number of Customers

	Three months ended June 30		Six months ended June 30	
	2002	2001	2002	2001
Residential	73,730	73,075	73,831	73,112
Commercial and Industrial	13,104	12,998	13,076	12,966
Other	64	66	65	66
Total Number of Customers. .	86,898	86,139	86,972	86,143

REVENUES

Total revenues from operations in the second quarter of 2002 decreased

$2.3 million or 3.5 percent compared with the same period in 2001. Operating revenues result from retail and wholesale sales of electricity.

Retail revenues in the second quarter of 2002 were $2.7 million or 5.9 percent higher compared with the same period in 2001, primarily as a result of the recognition of $2.1 million of revenues deferred during 2001 under a settlement order in the Company's retail rate filing that was approved by the Vermont Public Service Board in January 2001. Total retail MWh sales of electricity in the second quarter of 2002 decreased by 0.4 percent from the same quarter of 2001, reflecting a decrease in sales to industrial customers of 5.5 percent that was substantially offset by increased sales of 3.4 percent to small commercial and industrial customers and 1.5 percent to residential customers.

Retail revenues for the six months ended June 30, 2002 were $3.2 million or 3.3 percent higher when compared with the same period in 2001, reflecting the recognition of $4.3 million of deferred revenues, partially offset by decreased retail MWh sales of approximately 2.5 percent due to warmer than normal winter temperatures and a softening economy in 2002.

The Company currently estimates that its earnings for 2002 will approximate its allowed rate of return of 11.25% percent, and that it will recognize the remaining balance of $4.2 million of deferred revenues during 2002.

We sell wholesale electricity to others for resale. Our revenue from wholesale MWh sales of electricity decreased $4.7 million or 22.5 percent in the second quarter of 2002 compared with the same period in 2001. The decrease was due primarily to decreased sales under various arrangements with Hydro-Quebec.

OPERATING EXPENSES

POWER SUPPLY EXPENSES

Power supply expenses increased 1.4 percent or $0.6 million in the second quarter of 2002 over the same period in 2001, as a result of increased costs under our power supply agreement with Morgan Stanley, capacity cost increases at the Vermont Yankee nuclear plant and reimbursement of approximately $1.0 million received in 2001 for power supply costs incurred during previous periods. The increases in power supply costs in the second quarter of 2002 were partially offset by a reduction in costs arising from decreased sales of electricity to wholesale customers.

Power supply expenses at Vermont Yankee increased 42.8 percent or $2.5 million during the second quarter of 2002 compared with the second quarter of 2001, due to the deferral of maintenance and repair costs associated with a scheduled refueling outage in 2001. The sale of the VY generating plant is discussed under Part I, Item 2, "Investment in Associated Companies".

Company-owned generation expenses increased $0.7 million in the second quarter of 2002 compared with the same period in 2001 primarily due to a 2001 reimbursement of fuel costs expended in periods prior to 2001 to support system reliability. The Company received reimbursement of its costs of running its generating units for system reliability from the Independent System Operator of New England ("ISO") during the second quarter of 2001.

The cost of power that we purchased from other companies decreased 6.4 percent or $2.6 million in the second quarter of 2002 compared with the same period in 2001. This was primarily due to a $4.7 million reduction in wholesale electric revenues, and decreased expenses under the 9701 arrangement with Hydro-Quebec, pursuant to which Hydro-Quebec has the right to purchase electricity from the Company at rates below current market prices. These decreases were partially offset by higher power supply costs under both the MS contract and small power producer contracts. See the discussion under "Commitments and Contingencies-Power Contract Commitments" for more detail regarding the 9701 arrangement and the MS contract, including the recent renegotiation of the MS contract.

The 9701 arrangement allows Hydro-Quebec to exercise an option to purchase power from the Company at energy prices based on a 1987 contract. During the second quarter of 2002, $0.8 million in power supply expense was recognized to reflect the costs of option A, which are recognized ratably over the year. During the second quarter of 2001, $1.6 million in power supply expense was recognized to reflect the costs of options A and B. Hydro-Quebec has previously agreed not to call option B during the 2002 contract year. The cumulative amount of power purchased to date by Hydro-Quebec under option B is approximately 432,000 MWh out of a total of 600,000 MWh which may be called over the life of the of the arrangement.

Power supply expenses for the first half of 2002 decreased 6.6 percent or $6.6 million compared with the first half of 2001, primarily due to a reduction in low margin wholesale purchases and lower retail sales of electricity.

Power supply expense at Vermont Yankee increased $2.4 million or 17.3 percent for the first half of 2002 compared with the first half of 2001, primarily due to the deferral of maintenance and repair costs associated with a scheduled refueling outage in 2001. Vermont Yankee scheduled outage costs are deferred and amortized over an eighteen-month refueling cycle.

Company-owned generation expenses decreased $0.7 million or 29.7 percent in the first half of 2002 compared with the same period in 2001, primarily due to lower fuel costs and reduced need to run peak generation facilities for system reliability. 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 in the first quarter of 2001 caused by higher fuel costs.

Purchased power expense decreased $8.4 million or 9.9 percent in the first half of 2002 compared with the first half of 2001, primarily due to a $10.7 million decrease in wholesale electric revenues, decreased expenses under the 9701 arrangement with Hydro-Quebec and reductions in retail MWh sales of electricity.

Both the 9701 arrangement and any related forward purchase contracts are considered derivative instruments as defined by SFAS 133. On April 11, 2001, the VPSB issued an accounting order that allows the Company to defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133, and as a result, we do not anticipate SFAS 133 to cause earnings volatility. At June 30, 2002, the Company had a regulatory asset of approximately $33.7 million related to derivatives that the Company believes is probable of recovery. The regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

The cost of power purchased from MS for 2003 is expected to be approximately $6.0 million less than the cost of power purchased from MS during 2002. The remainder of our load requirements are substantially provided through our power supply contracts and arrangements with Hydro-Quebec and our entitlements to power generated at the Vermont Yankee nuclear plant now owned by Entergy.

OTHER OPERATING EXPENSES

Other operating expenses decreased 19.4 percent or $0.8 million in the second quarter of 2002 compared with the same period in 2001, as a result of increased reserves for medical benefits and vendor claims expensed in 2001.

Other operating expenses decreased 9.3 percent or $0.7 million in the first six months of 2002 compared with the same period in 2001 for the same reasons.

TRANSMISSION EXPENSES

Transmission expenses increased by approximately $0.5 million or 12.9% for the three months ended June 30, 2002 compared with the same period in 2001. The Company's relative share of transmission costs varies with the peak demand recorded on Vermont's transmission system. The Company's share of those costs has increased due to its increased load growth, relative to other Vermont utilities, experienced during the previous twelve months.

Transmission expenses increased by approximately $0.9 million or 13.8 percent for the six months ended June 30, 2002, compared with the same period in 2001 for the same reasons mentioned in the three month comparison. Congestion charges recorded in the first six months of 2002 and 2001 reflect the lack of adequate transmission or generation capacity in certain locations within New England, and these charges are allocated to all ISO New England members.

Congestion charges recorded in the first quarter of 2001 reflect the lack of adequate transmission or generation capacity in certain locations within New

England, and these charges are allocated to all ISO New England members. A system of locational pricing is likely to be adopted by ISO New England, as early as January 2003. Currently, it is expected that the Vermont zone will be set at state boundaries. The intent of locational pricing is to encourage generation and transmission solutions in areas experiencing constraints (congestion). The Company is unable to predict the magnitude or duration of future congestion charge allocations, but amounts could be material.

MAINTENANCE EXPENSES

Maintenance expenses were substantially unchanged during the second quarter of 2002 compared with the same period in 2001.

Maintenance expenses increased by approximately $0.7 million or 20.9% during the first half of 2002 compared with the same period in 2001, primarily due to the costs of repair from a series of minor storms in 2002 and increases in maintenance costs at our wind generation facility located in Searsburg, Vermont.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses decreased $0.2 million or 6.0 percent during the second quarter of 2002 compared with the same period in 2001 primarily due to decreased amortization of demand side management assets.

Depreciation and amortization expenses decreased $0.4 million or 5.1 percent during the first six months of 2002 compared with the same period in 2001 for the same reason.

TAXES OTHER THAN INCOME TAXES

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

INCOME TAXES

Income taxes decreased $0.9 million in the second quarter of 2002 compared with the same period in 2001 due to a decrease in pretax book income for core electric operations.

Income taxes decreased $0.7 million for the first six months of 2002 compared with the same period in 2001 for the same reason.

OTHER INCOME

Other income for the three and six months ended June 30, 2002 was essentially unchanged from the same period in 2001.

INTEREST CHARGES

Interest charges decreased $0.2 million or 12.2 percent in the second quarter of 2002 compared with the same period in 2001 primarily due to the redemption of first mortgage bonds in December 2001 and May 2002, partially offset by increased short-term borrowings and related interest costs.

Interest charges decreased $0.6 million or 17.2 percent in the first half of 2002 compared with the same period in 2001 for the same reasons.

LIQUIDITY AND CAPITAL RESOURCES

In the six months ended June 30, 2002, we spent $9.3 million principally for expansion and improvements of our transmission, distribution and generation plant. We expect to spend approximately $10.4 million during the remainder of 2002.

The Company renegotiated a 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by KeyBank National Association, ("KeyBank") with the renegotiated agreement expiring June 18, 2003 (the "Fleet-Key Agreement"). The Fleet-Key Agreement is for $35.0 million, unsecured, and allows the Company to choose either a daily variable prime rate, or a fixed term LIBOR-based rate. There was $10.4 million outstanding with an interest rate of 4.75 percent on the Fleet-Key Agreement at June 30, 2002. There was no non-utility short-term debt outstanding at June 30, 2002.

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

On June 21, 2002, the Company paid $1.0 million to redeem the remaining 7.32 percent Class E preferred stock outstanding.

In August 2002, the Company submitted a request to the Vermont Public Service Board to approve an issuance of first mortgage bonds sufficient to retire the Company's short and intermediate term debt.

The credit ratings of the Company's securities at June 30, 2002 are:

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

The following table presents payments contractually due by category:

In thousands Contractual Obligations at June 30, 2002	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term Debt.	$ 79,000	$ 8,000	$ 20,000	$ 14,000	$ 37,000
Revolving Credit.	10,400	10,400	-		
Interest on Long Term Debt.	60,013	5,123	8,208	6,681	40,001
Capital Lease	5,959	426	852	852	3,829
Preferred Stock	235	150	60	25	
Hydro-Quebec power supply contracts	691,343	47,977	96,360	100,836	446,170
MS power supply contract.	18,874 -	13,744	5,130	-	-
Total Contractual Cash Obligations.	$865,823	$85,819	$130,610	$122,394	$527,000

FUTURE OUTLOOK

COMPETITION AND RESTRUCTURING-The electric utility business continues to experience rapid and substantial changes. These changes are the result of the following trends:

disparity in electric rates, transmission, and generating capacity among and within various regions of the country;

improvements in generation efficiency;

increasing demand for customer choice;

consolidation through business combinations;

new regulations and legislation intended to foster competition, also known as restructuring; and

increasing volatility of wholesale market prices for electricity.

We are unable to predict what form future restructuring legislation, if adopted, will take and what impact that might have on the Company, but it could be material.

During 2001, the Town of Rockingham ("Rockingham"), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase an existing hydro-generation facility from a third party, and the associated distribution plant owned by the Company within Rockingham. In March 2002, voters in Rockingham authorized Rockingham to create a municipal utility by acquiring a municipal plant, which would include the Bellows Falls hydroelectric facility and the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that our remaining customers do not subsidize a Rockingham municipal utility.

NEW ACCOUNTING STANDARDS

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

EFFECTS OF INFLATION

Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This accounting provides reasonable financial statements but does not always take inflation into consideration. As rate recovery is based on 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. Assumptions used in the Blacks-Scholes model include a risk free rate of 5.02 percent, locked in forward commitment prices for 2002 and 2003, a forward market price averaging approximately $60 per MWh for periods beyond 2003 with an average of approximately 60,000 MWh per year. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are not recognized in earnings until the derivative positions are settled. Our daily net commodity position consists of purchased electric capacity. The table below presents market risk, estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in prices. Actual prices may differ materially from the table.

Commodity Price Risk At June 30, 2002

	Fair Value	Market Risk
	(in thousands)	
Net short position	$ 33,694	$ 2,341

GREEN MOUNTAIN POWER CORPORATION

JUNE 30,2002

PART II - OTHER INFORMATION

ITEM 1. Legal Proceedings
See Notes 3, 4 and 5 of Notes to Consolidated Financial Statements

ITEM 2. Changes in Securities
NONE

ITEM 3. Defaults Upon Senior Securities
NONE

ITEM 4. Submission of Matters to a Vote of Security Holders
At the Annual Shareholders Meeting held May 16, 2002, one item was voted upon by Shareholders. Shareholders elected the nominees listed below as Directors of the Company, with votes cast as indicated.

Elizabeth A. Bankowski, votes for, 4,834,640; withheld authority, 174,615; abstentions, 683,412.

William H. Bruett, votes for, 4,955,998; withheld authority, 53,257; abstentions, 683,412.

David R. Coates, votes for, 4,953,316; withheld authority, 55,939; abstentions, 683,412.

Directors continuing in office were Nordahl L. Brue, Merrill O. Burns, Lorraine E. Chickering, John V. Cleary, Christopher L. Dutton, and Euclid A. Irving. Thomas P. Salmon retired as Director and Chairman of the Board at the conclusion of the Annual Shareholders Meeting.

ITEM 5. Other Information
NONE

ITEM 6.
(A) EXHIBITS

Exhibit 10-b-90 Purchase Power Agreement between Entergy Nuclear Vermont Yankee LLC and Vermont Yankee Nuclear Power Corporation is attached and incorporated by reference herein.

Exhibit 10-b-91 First Amendment to Purchase Power Agreement, Exhibit 10-b-90 is attached and incorporated by reference herein.

(B) REPORTS ON FORM 8-K

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

May 16, 2002 Form 8-K announced the election of Nordahl Brue as Chairman of the Board of Directors of the Company, replacing the retiring Thomas P. Salmon.

June 27, 2002 Form 8-K announced the dismissal of Arthur Andersen as the Company's independent public accountants, with no disagreements cited.

July 17, 2002 Form 8-K announced the engagement of Deloitte & Touche LLP as the Company's independent certifying public accountants.

July 31, 2002 Form 8-K announced the completion of the sale of Vermont Yankee's nuclear generating plant to Entergy.

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: August 14, 2002 /s/Christopher L. Dutton

Christopher L. Dutton, Chief Executive Officer and President

Date: August 14, 2002 /s/Robert J. Griffin

Robert J. Griffin, (as Principal Financial Officer)

Controller and Treasurer