GREEN MOUNTAIN POWER CORP
Form 10-Q
August 06, 2004

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, 2004

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 BY CHECK MARK WHETHER THE REGISTRANT IS AN ACCELERATED FILER (AS DEFINED IN RULE 12B-2 OF THE EXCHANGE ACT). 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 $3.33 1/3 PAR VALUE	OUTSTANDING AT JULY 30, 2004
	5,086,688

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

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

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

AVAILABLE INFORMATION

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

PART I FINANCIAL INFORMATION
GREEN MOUNTAIN POWER CORPORATION
INDEX TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES
AT AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30,
2004 AND 2003

The accompanying notes are an integral part of the consolidated financial

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED COMPARATIVE INCOME STATEMENTS

	UNAUDITED			
	THREE MONTHS ENDED JUNE 30		SIX MONTH JUNE 30	
	2004	2003	2004	2
(in thousands, except per share data)				
Retail Revenues.	48,725	46,739	102,930	9
Wholesale Revenues.	5,860	17,716	14,778	
OPERATING REVENUES	$54,585	$64,455	$117,708	$13
OPERATING EXPENSES				
Power Supply				
Vermont Yankee Nuclear Power Corporation.	4,631	9,747	14,623	1
Company-owned generation.	1,214	1,112	3,446	
Purchases from others	29,136	36,101	57,101	7
Other operating.	4,394	3,663	8,745	
Transmission	4,029	3,490	7,738	
Maintenance.	2,425	2,150	4,696	

Depreciation and amortization	3,483	3,403	6,972	
Taxes other than income	1,713	1,826	3,492	
Income taxes	784	538	3,099	
Total operating expenses	51,809	62,030	109,912	12
OPERATING INCOME	2,776	2,425	7,796	
OTHER INCOME				
Equity in earnings of affiliates and non-utility operations	277	414	533	
Allowance for equity funds used during construction	109	90	224	
Other income (deductions), net	269	(23)	234	
TOTAL OTHER INCOME	655	481	991	
INTEREST CHARGES				
Long-term debt	1,633	1,755	3,267	
Other interest	84	90	141	
Allowance for borrowed funds used during construction	(69)	(60)	(143)	
TOTAL INTEREST CHARGES	1,648	1,785	3,265	
INCOME BEFORE PREFERRED DIVIDENDS AND DISCONTINUED OPERATIONS	1,783	1,121	5,522	
Dividends on preferred stock	-	1	-	
Income from continuing operations	1,783	1,120	5,522	
Income (loss) from discontinued segment, including provisions for operating losses during phaseout period	(1)	(8)	(7)	
NET INCOME APPLICABLE TO COMMON STOCK	$ 1,782	$ 1,112	$ 5,515	$

UNAUDITED

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2004	2003	2004	2003
Net income	$1,782	$1,112	$5,515	$5,184
Other comprehensive income, net of tax	-	-	-	-
Comprehensive income	$1,782	$1,112	$5,515	$5,184
Basic earnings per share	$ 0.35	$ 0.22	$ 1.09	$ 1.04
Diluted earnings per share	0.34	0.22	1.06	1.01
Cash dividends declared per share	$ 0.22	$ 0.19	$ 0.44	$ 0.38
Weighted average common shares outstanding-basic	5,072	4,969	5,058	4,964
Weighted average common shares outstanding-diluted	5,228	5,129	5,219	5,125

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Una For the Six J 2004
OPERATING ACTIVITIES:	
Income from continuing operations before preferred dividends	$ 5,522
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation and amortization.	6,972
Dividends from associated companies less equity income	38
Allowance for funds used during construction	(367
Amortization of deferred purchased power costs	1,681
Deferred income taxes.	704
Deferred purchased power costs	(432
Rate levelization liability.	(1,491
Environmental and conservation deferrals, net.	(706
Changes in:	
Accounts receivable and accrued utility revenues	2,701
Prepayments, fuel and other current assets	978
Accounts payable and other current liabilities	(1,092
Accrued income taxes payable and receivable.	(721
Deferred tax liability	(343
Other.	1,170
Net cash provided by operating activities.	14,615
INVESTING ACTIVITIES:	
Construction expenditures.	(8,536
Investment in associated companies	-
Return of Capital from associated companies.	110
Investment in nonutility property.	(255
Net cash used in investing activities.	(8,681
FINANCING ACTIVITIES:	
Payments to acquire treasury stock	-
Issuance of common stock	828
Reduction in long-term debt.	-
Short-term debt, net	(500
Cash dividends	(2,231
Net cash used in financing activities.	(1,903
Net increase in cash and cash equivalents.	4,031
Cash and cash equivalents at beginning of period	786
Cash and cash equivalents at end of period	4,817
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:	
Cash paid year-to-date for:	
Interest (net of amounts capitalized).	3,364

Income taxes 2,637

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

GREEN MOUNTAIN POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

(in thousands)	UNAUDITED JUNE 30 2004	UNAUDITED JUNE 30 2003	DECEMBER 31 2003
ASSETS			
UTILITY PLANT			
Utility plant, at original cost	$325,737	$314,275	$324,900
Less accumulated depreciation	115,239	108,020	110,111
Net utility plant	210,498	206,255	214,789
Property under capital lease.	5,047	5,522	5,047
Construction work in progress	15,139	13,980	9,026
Total utility plant, net.	230,684	225,757	228,862
OTHER INVESTMENTS			
Associated companies, at equity	5,732	14,329	5,896
Other investments	8,240	7,369	7,810
Total other investments	13,972	21,698	13,706
CURRENT ASSETS			
Cash and cash equivalents	4,817	2,007	786
Accounts receivable, less allowance for doubtful accounts of $790, $547 and $690. .	15,742	15,946	17,331
Accrued utility revenues.	5,617	6,038	6,729
Fuel, materials and supplies, average cost.	4,545	4,188	4,498
Prepayments	659	1,140	1,922
Other	665	356	422
Total current assets.	32,045	29,675	31,688
DEFERRED CHARGES			
Demand side management programs	6,994	6,471	6,713
Purchased power costs	725	114	2,574
Pine Street Barge Canal	12,954	13,019	12,954
Net power supply deferral	12,350	21,160	19,734
Power supply derivative asset	12,210	6,586	3,990
Other deferred charges.	9,349	10,546	9,625
Total deferred charges.	54,582	57,896	55,590
NON-UTILITY			
Other current assets.	-	8	217
Property and equipment.	248	249	248
Other assets.	577	663	640
Total non-utility assets.	825	920	1,105

TOTAL ASSETS	$332,108	$335,946	$330,951

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 JUNE 30 2004	UNAUDITED JUNE 30 2003	DECEMBER 31 2003
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION			
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 5,905,627, and 5,803,596 and 5,860,854)	$ 19,685	$ 19,345	$ 19,536
Additional paid-in capital	76,761	75,469	76,081
Retained earnings	26,071	19,469	22,786
Accumulated other comprehensive income	(1,787)	(2,374)	(1,787)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)	(16,701)
Total common stock equity	104,029	95,208	99,915
Redeemable cumulative preferred stock	-	55	-
Long-term debt, less current maturities	93,000	93,000	93,000
Total capitalization	197,029	188,263	192,915
CAPITAL LEASE OBLIGATION	4,898	5,496	4,963
CURRENT LIABILITIES			
Current maturities of preferred stock	-	30	-
Current maturities of long-term debt	-	8,000	-
Short-term debt	-	-	500
Accounts payable, trade and accrued liabilities	8,353	4,358	8,493
Accounts payable to associated companies	5,305	8,535	6,821
Rate levelization liability	1,986	4,329	2,970
Accrued income taxes	(88)	5,065	633
Customer deposits	930	840	968
Interest accrued	1,134	1,182	1,152
Other	1,796	965	1,178
Total current liabilities	19,416	33,304	22,715
DEFERRED CREDITS			
Power supply derivative liability	24,560	27,746	23,724
Accumulated deferred income taxes	34,508	27,662	34,009
Unamortized investment tax credits	2,710	2,989	2,848
Pine Street Barge Canal cleanup liability	6,649	6,720	7,356
Accumulated cost of removal	21,907	20,377	21,238
Other deferred liabilities	18,939	21,562	19,693
Total deferred credits	109,273	107,056	108,868

COMMITMENTS AND CONTINGENCIES, NOTE 3			
NON-UTILITY			
Net liabilities of discontinued segment.	1,492	1,827	1,490
Total non-utility liabilities.	1,492	1,827	1,490
TOTAL CAPITALIZATION AND LIABILITIES	$332,108	$335,946	$330,951

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

UNAUDITED

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In thousands	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2004	2003	2004	2003
Balance - beginning of period.	$25,406	$19,300	$22,786	$16,171
Net Income	1,782	1,113	5,515	5,186
Cash Dividends-redeemable cumulative preferred stock	-	(1)	-	(2)
Cash Dividends-common stock.	(1,117)	(943)	(2,230)	(1,886)
Balance - end of period.	$26,071	$19,469	$26,071	$19,469

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2004

PART I-ITEM 1

1. SIGNIFICANT ACCOUNTING POLICIES

It is our opinion that the financial information contained in this report reflects all normal, recurring adjustments necessary to present a fair statement of results for the periods reported, but such results are not necessarily indicative of results to be expected for the year due to the seasonal nature of our business and include other adjustments discussed elsewhere in this report necessary to reflect fairly the results of the interim periods. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. However, the disclosures herein, when read with the Green Mountain Power Corporation (the "Company" or "GMP") annual report for 2003 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, of which $1.1 million and $4.4 million were recognized during 2003 and 2002, respectively. The Company recognizes deferred revenues based on its current forecast of amounts necessary to achieve its allowed rate of return on equity for its utility operations. For the six months ended June 30, 2004, the Company recognized deferred revenues of $1.5 million. The remaining $1.5 million will be used to offset increased costs or write off regulatory assets during 2004. For the three months ended June 30, 2004, the Company recognized deferred revenues of $742,000 compared with the same period in 2003 when the Company deferred revenue recognition of $271,000. The Company did not recognize or defer revenues for the six months ended June 30, 2003.

In December 2003, the VPSB approved a rate plan for the period 2003 through 2006 (the "2003 Rate Plan"), jointly proposed by the Company and the Vermont Department of Public Service (the "Department" or the "DPS"). The 2003 Rate Plan is summarized below under the heading "Rates.""

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.

For incentive stock options issued prior to 2003, the Company applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for its stock option plan and has adopted the disclosure-only provisions of SFAS 123, "Accounting for Stock-Based Compensation" as amended by SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - and amendment of SFAS 123." For options granted on or after January 1, 2003, the Company applies the accounting provisions of SFAS 123. The following table illustrates the effect on net income and earnings per share, as if the fair value method had been applied to all outstanding and unvested awards in each period. The fair value of options at the date of grant was estimated using the Black-Scholes option-pricing model. Had the Company expensed stock-based compensation under SFAS 123 for options granted prior to 2003, the Company's diluted earnings would have been reduced by $0.01 and $0.01 per share for the six months ended June 30, 2004 and 2003, respectively.

Pro-forma net income	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	2004	2003
In thousands, except per share amounts				
Net income reported.	$1,782	$1,112	$5,515	$5,184
Pro-forma net income	1,762	1,072	5,474	5,103
Earnings per share				
As reported-basic.	0.35	0.22	1.09	1.04
Pro-forma basic.	0.35	0.22	1.08	1.03
As reported-diluted.	0.34	0.22	1.06	1.01
Pro-forma diluted.	0.34	0.21	1.05	1.00

UNREGULATED OPERATIONS

Our wholly owned subsidiaries are Northern Water Resources, Inc. ("NWR"); Green Mountain Propane Gas Company Limited ("GMPG"); GMP Real Estate Corporation; Green Mountain Power Investment Company ("GMPIC"); and Green Mountain Resources, Inc. ("GMRI"). GMRI and GMPG were dissolved in March and May 2004, respectively, with no gain or loss resulting from dissolution. We also have a rental water heater program that is not regulated by the VPSB. The results of these subsidiaries, and the Company's unregulated rental water heater program, excluding NWR, are included in earnings of affiliates and non-utility operations in the Other (Deductions) Income section of the Consolidated Statements of Income. NWR's results are included in Gain/Loss from Discontinued Operations.

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).

(in thousands)	Three months ended June 30 2004	Three months ended June 30 2003	Six Months Ended June 30 2004	Six Months Ended June 30 2003
Gross Revenue.	$25,051	$49,014	$74,197	$96,982
Net Income Applicable. to Common Stock	128	722	$ 271	1,407
Equity in Net Income .	43	140	91	267

On July 31, 2002, Vermont Yankee Nuclear Power Corporation ("VYNPC") announced that the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee ("ENVY") had been completed.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the plant resulted in a shutdown of the ENVY plant. The outage ended on July 7, 2004. In response to the Company's request, the VPSB issued a preliminary accounting order allowing the Company to defer and amortize over a three-year period beginning July 1, 2004 its incremental replacement power costs during the outage totaling approximately $500,000. Since the Company no longer owns, through VYNPC, an interest in the nuclear plant we are not responsible for any plant repairs or maintenance costs during outages.

In 2003, ENVY sought PSB approval to increase generation at its Vermont Yankee plant by approximately 20 percent or 110 megawatts. On November 5, 2003, the DPS announced that it had agreed to support ENVY's proposed uprate, including ENVY's agreement to provide outage protection indemnification for the Company and Central Vermont Public Service Corporation in the event that the uprate causes temporary reductions in output that would require us to buy higher-cost replacement power. The outage protection coverage will be in place for three years for uprate-related outages. Under this Ratepayer Protection Proposal ("RPP"), we have indemnification rights up to approximately $1.6 million to cover uprate-related reductions in output. In early 2004, the PSB issued an order approving the uprate subject to certain conditions.

On February 10, 2004, ENVY notified VYNPC that it expects that the plant output will be reduced beginning after the April 2004 scheduled refueling outage, and continuing until ENVY receives Nuclear Regulatory Commission ("NRC") approval for the uprate, which is expected no earlier than November 2004. This will reduce our 106 MW entitlement by about 5 MW during this period. We believe such a reduction will be covered by the terms of the RPP discussed above.

In April 2004, in response to a NRC inspection conducted during the ENVY plant's scheduled refueling outage, ENVY reported that two short spent fuel rod segments were not in what ENVY believed to be their documented location in the spent fuel pool. According to ENVY, the rods in 1979 were placed in a special stainless steel container in the spent fuel pool. After initial review and visual inspection of the spent fuel pool, ENVY did not locate the fuel rod segments.

By letter dated May 5, 2004, ENVY notified VYNPC that based on the terms of the Purchase and Sale Agreement dated August 1, 2001, and facts at that time, it was ENVY's view that costs associated with the spent fuel rod segment inspection effort were the responsibility of VYNPC. VYNPC responded that based on the information at that time, there was no basis for ENVY to claim the inspection was VYNPC's responsibility. Subsequently, ENVY's continuing documentation review led to the discovery of the fuel rod segments in a container in the spent fuel pool. The NRC will begin its own investigation next month into ENVY's accounting for these segments. We cannot predict the outcome of this matter at this time.

The Company's ownership share of VYNPC has increased from approximately 19.0 percent in 2002 to approximately 33.6 percent currently, due to VYNPC's purchase of certain minority shareholders' interests during November 2003. The Company's entitlement to energy produced by the ENVY nuclear plant remains at approximately 20 percent of plant production.

VERMONT ELECTRIC POWER COMPANY, INC. ("VELCO")
Percent ownership: 28.4% common
30.0% preferred

VELCO is a corporation engaged in the transmission of electric power within the State of Vermont. VELCO has entered into transmission agreements with the State of Vermont and various electric utilities, including the Company, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to those using VELCO's transmission system. The Company is obligated to provide its proportionate share of the equity capital requirements of VELCO through continuing purchases of its common stock, if necessary. The Company plans to make capital investments of up to $20 million in VELCO through 2007 in support of various transmission projects.

	Three months ended June 30		Six Months Ended June 30	
	2004	2003	2004	2003
(in thousands)				
Gross Revenue	$6,543	$5,635	$12,876	$11,270
Net Income.	308	349	618	622
Equity in Net Income.	85	91	131	197

The Company has evaluated its relationship with VELCO and VYNPC under the requirements of FIN 46R and has determined that it is not the primary beneficiary of VELCO or VYNPC. Therefore the financial results of VELCO and VYNPC have not been consolidated into the Company's financial statements.

3. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL MATTERS

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

PINE STREET BARGE CANAL SUPERFUND SITE - In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. We have estimated total future costs of the Company's future obligations under the consent decree to be approximately $6.6 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $13.0 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of incurred costs over 20 years without a return. The amortization will be allowed in future rates, without disallowance or adjustment, until fully amortized.

RATES

RETAIL RATE CASES - On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed earlier in the year by the Company and the Department. The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

The Company's rates will remain unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase is required for the Company to earn its allowed rate of return, the Company will implement the lesser rate increase.

The Company may seek additional rate increases or deferral of costs in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.

The Company's allowed return on equity is reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on utility operations are capped at 10.5 percent. Any excess earnings in 2004 will be applied to reduce regulatory assets. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

The Company has carried forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003, from the Company's 2001 Settlement Order (summarized below). These revenues will be applied in 2004 to offset increased costs or, if applicable, reduce regulatory assets as determined by the DPS.

The Company will amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

As required, the Company filed with the VPSB in early 2004 a new fully allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design is subject to VPSB approval and is not expected to adversely affect operating results.

The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan.

In January 2001, the VPSB approved a rate case settlement (the "2001 Settlement Order") between the Company and the DPS. The 2001 Settlement Order included a rate increase of 3.42 percent effective January 2001, setting the Company's rates at levels that recover the Company's Hydro Quebec/Vermont Joint Owners Contract (the "VJO Contract") costs, and effectively ending regulatory disallowances experienced by the Company from 1998 through 2000. Under the 2001 Settlement Order, the Company agreed to an earnings cap on core utility operations of 11.25 percent return on equity, with amounts earned over the limit being used to write off regulatory assets.

The 2001 Settlement Order also imposed 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, adjusted for inflation; and

The Company's further investment in non-utility operations is restricted until new rates go into effect, which will occur in January 2005.

POWER CONTRACT COMMITMENTS

On February 11, 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") designed to manage price risks associated with changing fossil fuel prices. In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006.

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley from part of our portfolio of power resources at predefined operating and pricing parameters, provided that sales of power from sources other than Company-owned generation comply with the predefined operating parameters and predefined or indexed pricing parameters. Morgan Stanley sells to the Company, at a predefined price, power sufficient to serve pre-established load requirements. We remain responsible for resource performance and availability. Morgan Stanley provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company reduced the power that it sells to Morgan Stanley. The output of some of our power-supply resources, including purchases pursuant to our Hydro Quebec and VYNPC contracts, which were sold to Morgan Stanley through 2003, are no longer included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley is expected to reduce wholesale revenues by approximately $56 million during 2004 when compared with 2003, and correspondingly to reduce power supply expense by a similar amount. We do not expect this change to adversely affect the Company's opportunity to earn its allowed rate of return during 2004.

The Company's current purchases under the VJO Contract with Hydro Quebec are as follows: (1) Schedule B -- 68 megawatts of firm capacity and associated energy to be delivered at the Highgate interconnection for twenty years beginning in September 1995; and (2) Schedule C3 -- 46 megawatts of firm capacity and associated energy to be delivered at interconnections to be determined at any time for 20 years, beginning in November 1995.

We sometimes experience energy delivery deficiencies under the VJO Contract as a result of outages or other problems with the transmission interconnection facilities over which we schedule deliveries. When such deficiencies occur, we purchase replacement energy on the wholesale market, usually at prices that are higher than VJO Contract costs.

Our contracts with Hydro Quebec contain cross default provisions that allow Hydro Quebec to invoke "step-up" provisions under which the other Vermont utilities that are also parties to the contract would be required to purchase their proportionate share of the power supply entitlement of any defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro Quebec.

Under the Company's 9701 arrangement with Hydro Quebec, Hydro Quebec paid $8.0 million to the Company in 1997. In return for this payment, we provided Hydro Quebec options for the purchase of power. Commencing April 1, 1998, and effective through the term of the VJO Contract, which ends in 2015, Hydro Quebec may purchase up to 52,500 MWh on an annual basis ("option A") at the VJO Contract energy price, which is substantially below current market prices. The cumulative amount of energy that may be purchased under option A may not exceed 950,000 MWh (52,500 MWh in each contract year).

Over the same period, Hydro Quebec may exercise an option to purchase up to 200,000 MWh on an annual basis at the VJO Contract energy price ("option B"). The cumulative amount of energy that may be purchased under option B may not exceed 600,000 MWh. As of June 30, 2004, Hydro Quebec had purchased 513,000 MWh under option B. Hydro Quebec has exercised its option to purchase 105,000 MWh under options A and B during the months of July and August 2004, as anticipated by the Company. The Company expects Hydro Quebec to call its remaining entitlements of approximately 35,000 MWh under option B during 2005.

In 2003, Hydro Quebec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges.

Hydro Quebec exercised options A and B for 2004, and the Company has purchased replacement power at a net cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at a net cost of $1.1 million.

Under the VJO Contract, Hydro Quebec has the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the contract. Hydro Quebec exercised the first of these load reduction options, effective for the year 2003. The net cost of Hydro Quebec's exercise of this option increased power supply expense during 2003 by approximately $1.2 million. During 2003, Hydro Quebec exercised its second option to reduce the load factor for 2004, which we estimate will increase power supply expense in 2004 by approximately $1.0 million. Hydro Quebec exercised its third and final option in 2004 to reduce deliveries occurring principally during 2005, resulting in an estimated cost of replacement power of $1.0 million to $1.5 million, based on current wholesale market prices for 2005. The Vermont Joint Owners, including the Company, retain two options to increase the load factor to 80 percent from 75 percent after 2005.

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

4. SEGMENTS AND RELATED INFORMATION

The Company's electric utility operation is its only operating segment. The electric utility is engaged in the procurement, generation, distribution and sale of electrical energy in the State of Vermont and also reports the results of its wholly owned unregulated subsidiaries (GMPG, GMRI, GMPIC and GMP Real Estate) and the rental water heater program as a separate line item in the Other Income section in the Consolidated Statement of Income.

NWR is an unregulated business that invested in energy generation, energy efficiency and wastewater treatment projects. As of June 30, 2004, most of NWR's net assets and liabilities have been sold or otherwise disposed. The remaining net liability reflects expected warranty obligations.

5. DERIVATIVE INSTRUMENTS AND RISK MANAGEMENT

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

All of the Company's power supply contract costs are currently being recovered through rates approved by the VPSB. The Company's most significant power supply contracts are the Hydro Quebec Vermont Joint Owners ("VJO") Contract (the "VJO Contract") and the VYNPC contract (the "VYNPC Contract"), which together supply approximately 75 percent of our retail load.

We expect approximately 90 percent of our estimated customer demand ("load") requirements through 2006 to be met by our contracts and generation and other power supply resources. These contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices.

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Implementation of New England's wholesale market for electricity has increased volatility of wholesale power prices. Periods frequently occur when weather, availability of power supply resources and other factors cause significant differences between customer demand and electricity supply. Because electricity cannot be stored, in these situations the Company must buy or sell the difference into a marketplace that has experienced volatile energy prices. Volatility and market price trends also make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief.

The Company has established a risk management program designed 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. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Some of these transactions present the risk of potential losses from adverse changes in commodity prices. Our risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions. Our principal power supply contract counter-parties and generators, Hydro Quebec, ENVY and Morgan Stanley Capital Group, Inc., all currently have investment grade credit ratings.

The Morgan Stanley Contract (described above under "Power Contract Commitments") is used to hedge our power supply costs against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management has estimated the fair value of the future net benefit of this arrangement at June 30, 2004 to be approximately $12.2 million.

The Company's 9701 arrangement with Hydro Quebec (described under "Power Contract Commitments") grants Hydro Quebec an option to call power at prices that are expected to be below 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, 2004 is approximately $24.6 million. We sometimes use forward contracts to hedge forecasted calls by Hydro Quebec under the 9701 arrangement.

The table below presents assumptions used to estimate the fair value of the Morgan Stanley Contract and the 9701 arrangement. The forward prices for electricity used in this analysis are consistent with the Company's current long-term wholesale energy price forecast.

	Option Value Model	Risk Free Interest Rate	Price Volatility	Average Forward Price	Contract Expires

Morgan Stanley Contract	Deterministic	1.2%	32%-29%	$ 58	2006
9701 Arrangement. . . .	Black-Scholes	3.8%	48%-27%	$ 62	2015

The table below presents the Company's market risk of the Morgan Stanley and Hydro Quebec derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to approximately $882,000. Actual results may differ materially from the table illustration. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred.

Commodity Price Risk	At June 30, 2004	
	Fair Value(Cost)	Market Risk
	(in thousands)	
Morgan Stanley Contract	$ 12,210	$ 2,310
9701 Arrangement. . . .	(24,560)	(3,192)
	(12,350)	(882)

If a derivative instrument were 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. NEW ACCOUNTING STANDARDS

In January 2003 and December 2003, the Financial Accounting Standards Board issued Interpretation 46 and 46R (Revised), respectively, Consolidation of Variable Interest Entities ("VIEs"). This interpretation clarified application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaced current accounting guidance relating to consolidation of certain special purpose entities. FIN 46 and FIN 46R define VIEs as entities that are unable to finance their ongoing operations without additional subordinated financing. FIN 46R requires identification of the Company's participation in VIEs and consolidation of those VIEs of which the Company is the primary beneficiary. The Company adopted FIN 46 at December 31, 2003 and FIN 46R at March 31, 2004, and was not required to consolidate any existing interests pursuant to the requirements of FIN 46 or FIN 46R.

The Company provides health care, life insurance, prescription drug and other benefits to retired employees who meet certain age and years of service requirements. Under certain circumstances, eligible retirees are required to make contributions for postretirement benefits. On May 19, 2004, the FASB issued FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act"), ("FAS No. 106-2") which superseded FSP 106-1, which allowed employers to voluntarily recognize the impact of the Act. This was in response to a new law regarding prescription drug benefits under Medicare ("Medicare Part D") and a federal subsidy to sponsors of retiree health care benefit plans that are at least actuarially equivalent to Medicare Part D. Currently, SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, ("SFAS No. 106") requires that changes in relevant law be considered in current measurement of postretirement benefit costs. The Company had elected to defer recognition of any impact under FSP 106-1. FSP 106-2 provides that if the effect of the Act is not considered a significant event, the measurement date for adoption of FSP 106-2 is delayed until the next regular measurement date, which is September 30, 2004 for the Company. The Company has concluded that the effect is not significant. Therefore, measures of the accumulated postretirement benefit obligation and the net periodic postretirement benefit cost do not reflect the effects of the new law.

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. On February 9, 2004, the Board of Directors of the Company adopted the 2004 Stock Incentive Plan and such plan was approved by the Company's shareholders at the Company's 2004 Annual Meeting of Shareholders. Restricted stock units issued under the plans are subject to vesting schedules of between several months and two years.

Reconciliation of net income available for common shareholders and average shares	Three months ended June 30 2004	Three months ended June 30 2003	Six months ended June 30 2004	Six months ended June 30 2003
(in thousands)				
Net income before preferred dividends. .	$1,782	$1,113	$5,515	$5,186
Preferred stock dividend requirement . .	-	1	-	2
Net income applicable to common stock	$1,782	$1,112	$5,515	$5,184
Average number of common shares-basic. .	5,072	4,969	5,058	4,964
Dilutive effect of stock options	156	160	161	161
Average number of common shares-diluted.	5,228	5,129	5,219	5,125

GREEN MOUNTAIN POWER CORPORATION
PART I-ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
JUNE 30, 2004

EXECUTIVE OVERVIEW - Green Mountain Power Corporation (the "Company") generates virtually all of its earnings from retail electricity sales. Our retail electricity sales grow at an average annual rate of between one and two percent, about average for most electric utility companies in New England. While wholesale revenues are significant, they have relatively minor impact on our operating results and financial condition. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

The Company increased its dividend in February 2004 from an annual rate of $0.76 per share to $0.88 per share. The Company's dividend payout ratio remains comparatively low, at less than 45 percent of 2003 earnings. We expect to grow our dividend payout ratio to between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

Fair regulatory treatment is fundamental to maintaining the Company's financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders. In December 2003, the Company received approval from the VPSB of a new rate plan covering the period 2003 through 2006, which sets rates at levels the Company believes will provide an improved opportunity to recover our costs, and to earn our allowed rate of return of 10.5 percent.

Power supply expenses are equivalent to approximately 65 percent of total revenues. The Company's need to seek rate increases from its customers frequently moves in tandem with increases in our power supply costs. We have entered into long-term power supply contracts for most of our energy needs. All of our power supply contract costs are currently being recovered in the rates we charge our customers. The risks associated with our power supply resources, including outage, curtailment, and other delivery risks, the timing of contract expirations, the volatility of wholesale prices, and other factors impacting our power supply resources and how they relate to customer demand are discussed below under Item 3, "Quantitative and Qualitative Disclosure about Market Risk, and Other Risk Factors."

We also discuss other risks, including load risk related to our largest customer, International Business Machines Corporation ("IBM"), and contingencies that could have a significant impact on future operating results and our financial condition.

Growth opportunities beyond the Company's normal investment in its infrastructure include a planned increase in our equity investment in Vermont Electric Power Company, Inc. ("VELCO") and a planned increase in sales of utility services.

In this section, we explain the general financial condition and the results of operations for the Company and its subsidiaries. This explanation 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 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 affect our overall financial condition.

Management believes the most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate; the manner in which we account for certain power supply arrangements that qualify as derivatives; the assumptions that we make regarding defined benefit plans; and revenue recognition, particularly as it relates to unbilled and deferred revenues. These accounting policies, among others, affect the Company's significant judgments and estimates used in the preparation of its consolidated financial statements.

There are statements in this section that contain projections or estimates that are considered to be "forward-looking" as defined by the Securities and Exchange Commission (the "SEC"). In these statements, you may find words such as believes, 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 include:
- regulatory and judicial decisions or legislation
- changes in regional market and transmission rules
- energy supply and demand and pricing
- contractual commitments
- availability, terms, and use of capital
- general economic and business environment
- changes in technology

nuclear and environmental issues
industry restructuring and cost recovery (including stranded costs)
weather

We address these items in more detail below.

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

AS YOU READ THIS SECTION IT MAY BE HELPFUL TO REFER TO THE CONSOLIDATED FINANCIAL STATEMENTS AND NOTES IN PART I-ITEM 1.

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	
	2004	2003	2004	2003
Utility business	$0.32	$0.20	$1.03	$1.00
Unregulated businesses .	0.03	0.02	0.06	0.04
Earnings from:				
Continuing operations. .	0.35	0.22	1.09	1.04
Discontinued operations.	-	-	-	-
Basic earnings per share	$0.35	$0.22	$1.09	$1.04

OPERATING RESULTS.

The Company recorded basic earnings per share from utility operations of $0.32 in the quarter ended June 30, 2004, compared with utility earnings of $0.20 per share in the same quarter of 2003. Earnings in 2004 were higher than the second quarter of 2003 principally due to a $0.12 per share increase in deferred revenues recognized. Higher retail sales and lower power supply expenses offset increases in other operating, transmission and maintenance expenses during the quarter. As disclosed in our 2003 Annual Report, a planned reduction in wholesale sales pursuant to the Morgan Stanley Contract was offset by a reduction in power purchased to fulfill those sales.

Basic earnings per share for the six months ended June 30, 2004 were $1.09 compared with basic earnings per share of $1.04 for the same period in 2003. Earnings improved primarily due to increased recognition of deferred revenues, increased retail sales of electricity and lower power supply expense, that were partially offset by a one time benefit that occurred during 2003 for additional energy deliveries that were sold in the wholesale market at unusually high prices, adding approximately $0.15 per share to 2003 earnings, and by increased other operating expenses.

Operating results also include earnings of approximately $0.03 per share and $0.06 per share for the three and six months ended June 30, 2004 from the Company's rental water heater business and did not change materially when compared with the same periods in 2003.

OPERATING REVENUES AND MWH SALES

Our revenues from operations, megawatt hour ("MWh") sales and average number of customers for the three and six months ended June 30, 2004 and 2003 are summarized below:

	Three months ended June 30		Six months ended June 30	
	2004	2003	2004	2003
(dollars in thousands)				
Operating revenues				
Retail.	$ 47,881	$ 45,935	$ 101,229	$ 98,372
Sales for Resale. . .	5,860	17,716	14,778	37,641
Other	844	804	1,701	1,387
Total Operating Revenues.	$ 54,585	$ 64,455	$ 117,708	$ 137,400
MWh Sales-Retail.	459,796	450,945	974,879	959,409
MWh Sales for Resale. . .	107,919	534,644	253,620	1,080,562
Total MWh Sales	567,715	985,589	1,228,499	2,039,971

Average Number of Customers

	Three months ended June 30		Six months ended June 30	
	2004	2003	2004	2003
Residential	75,253	74,488	75,341	73,861
Commercial and Industrial	13,480	13,314	13,476	13,194
Other	62	65	62	65
Total Number of Customers. .	88,795	87,867	88,879	87,120

REVENUES

Total operating revenues in the second quarter of 2004 decreased $9.9 million or 15.3 percent compared with the same period in 2003, primarily as a result of a decrease in wholesale sales to Morgan Stanley under the Morgan Stanley Contract (described in Part I, Item I, No. 3 under "Power Contract Commitments"). This decrease was partially offset by an increase of approximately $1.9 million in retail operating revenues. The increase in retail revenues had a favorable impact on earnings and resulted principally from a $1.0 million increase in commercial and industrial customer revenues and a $1.0 million increase in deferred revenue recognition. Total retail MWh sales of electricity in the second quarter of 2004 increased 2.0 percent from the same quarter of 2003, primarily as a result of an economic recovery and growth resulting in an increase in commercial and industrial sales of 3.4 percent, partially offset by a decrease in residential sales of 1.7 percent due to milder weather in 2004.

Retail operating revenues reflected a $1.0 million increase in the recognition of deferred revenues during the second quarter of 2004, compared with the same quarter of 2003. Revenues were deferred during 2001 in accordance with the settlement of the Company's retail rate case approved by the Vermont Public Service Board (the "VPSB") in January 2001 (the "2001 Settlement Order"). The 2001 Settlement Order resulted in the elimination of seasonal rates, generating an additional $8.5 million in cash flow in 2001. The VPSB has issued orders providing that recognition of this additional $8.5 million of revenue be deferred and then recognized to offset increased costs during 2001, 2002, 2003 and 2004. As of June 30, 2004, the Company has $1.5 million in remaining unrecognized deferred revenues, which will be used to earn an allowed return or write off regulatory assets during 2004.

In December 2003, the VPSB approved a rate plan between the Vermont Department of Public Service and the Company that allows the Company to raise rates by 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. The 1.9 percent increase is expected to provide approximately $4 million in retail operating revenues during 2005.

The Company's major industrial customer, International Business Machines ("IBM"), accounted for 16.6% of retail sales revenue in 2003. The Company currently estimates, based on a number of projected variables, the retail rate increase required from all retail customers by a hypothetical shutdown of the IBM facility to be in the range of five to eight percent, inclusive of projected related declines in sales to residential and commercial customers.

We sell wholesale electricity to others for resale. Our revenue from wholesale MWh sales of electricity decreased approximately $11.9 million or 66.9 percent in the second quarter of 2004 compared with the same period in 2003, reflecting decreased sales of electricity to Morgan Stanley under our Morgan Stanley Contract. We do not expect the reduction in sales to Morgan Stanley to adversely affect the Company's earnings in 2004 or future years.

Retail operating revenues reflected a $1.5 million increase in the recognition of deferred revenues during the first six months of 2004, compared with the same period of 2003, an increase of $1.0 million or 3.5 percent in commercial and industrial revenues during the same comparative periods, and a decrease of approximately $88,000 in revenues from residential and other customers.

Total retail MWh sales of electricity in the first half of 2004 increased 1.8 percent when compared with the first half of 2003, primarily as a result of an increase in commercial and industrial sales of 2.9 percent and an increase of 0.9 percent in residential sales.

Wholesale revenues decreased $22.9 million or 60.7 percent during the first six months of 2004, compared with the same period in 2003, as a result of reduced sales under the Morgan Stanley Contract. Wholesale revenues also declined as a result of decreased sales of power arising from added deliveries of electricity under a long-term contract with Hydro Quebec. During the first quarter of 2003, delivery of past power supply contract deficiencies by Hydro Quebec resulted in additional energy availability that the Company sold when market energy prices were unusually high. We estimate that these sales increased quarterly earnings by approximately $0.15 per share in 2003. There are no further deficiencies to be rescheduled and the Company does not expect this benefit to reoccur.

OPERATING EXPENSES

POWER SUPPLY EXPENSES

Power supply expenses decreased $12.0 million or 25.6 percent in the second quarter of 2004 compared with the same period in 2003, primarily as a result of an $11.0 million decline in purchases under the Company's power supply contract with Morgan Stanley (described in Part I, Item I, No. 3 under "Power Contract Commitments").

Power supply expenses from VYNPC decreased $5.1 million or 52.5 percent during the second quarter of 2004 compared with the same period of 2003, primarily due to decreased output at the ENVY nuclear power plant due to planned and unplanned outages. See Part I, Item 1, Note 2, Investment in Associated Companies-Vermont Yankee, for a more detailed discussion of the effect of these outages.

Company-owned generation expenses increased $102,000 or 9.2 percent in the second quarter of 2004 compared with the same period in 2003, primarily due to increased fuel prices for production at peak generation facilities. Peak generation facilities are run only to maintain system reliability or when wholesale energy prices are extremely high.

The cost of power that we purchased from other companies decreased $7.0 million or 19.3 percent in the second quarter of 2004 compared with the same period in 2003, primarily due to an $11.0 million decrease in purchases from Morgan Stanley, partially offset by an increase in costs of power purchased from NEPOOL and other sources to replace the decreased output at the ENVY plant during outages, to supply increased retail sales to customers and to replace reduced deliveries from Hydro Quebec.

During the second quarter of 2004, $751,000 in power supply expense was recognized to reflect the costs of the Company's 9701 arrangement with Hydro Quebec compared with $1.1 million in power supply expense for the same quarter in 2003. The cumulative amount of power purchased at June 30, 2004 by Hydro Quebec under option B is approximately 513,000 MWh, out of a total of 600,000 MWh, which may be called over the life of the arrangement.

Hydro Quebec has exercised options A and B for 2004, and the Company has purchased a forward contract for replacement power at a net cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at a net cost of $1.1 million.

Under the VJO Contract, Hydro Quebec has the right to reduce the load factor from 75 percent to 65 percent a total three times over the life of the contract. Hydro Quebec exercised the first of these load reduction options, effective for the year 2003. The net cost of Hydro Quebec's exercise of this option increased power supply expense during 2003 by approximately $1.2 million. During 2003, Hydro Quebec exercised its second option to reduce the load factor for 2004, which we estimate will increase power supply expense in 2004 by approximately $1.0 million. Hydro Quebec exercised its final option in 2004 for deliveries occurring principally during 2005, at an estimated cost of $1.0 million to $1.5 million, based on current wholesale market prices, for 2005.

Both the 9701 arrangement and any related forward purchase contracts are considered derivative instruments as defined by SFAS 133. On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effect relating to future periods caused by application of SFAS 133, and as a result, we do not anticipate SFAS 133 to affect earnings. The current costs of both the 9701 arrangement and other forward purchase arrangements, including our Morgan Stanley Contract, are being fully recovered in our retail rates. At June 30, 2004, the Company had a net regulatory asset of approximately $12.4 million related to derivatives that the Company believes are probable of recovery. The fair value of the regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

Power supply expenses decreased $21.0 million or 21.9 percent in the first half of 2004 compared with the same period in 2003, as a result of decreased wholesale sales of electricity that were offset by a $25.9 million decline in purchases under the Company's power supply contract with Morgan Stanley.

Power supply expenses from Vermont Yankee decreased $4.7 million or 24.2 percent during the first half of 2004 compared with the same period of 2003, primarily due to a decrease in energy provided under the Power Purchase Agreement between VY and ENVY, primarily for the outage reasons discussed earlier. The sale of the VY generating plant is discussed under Part I, Item 1, Note 2, "Investment in Associated Companies".

Company-owned generation expenses decreased $1.0 million or 23.2 percent in the first half of 2004 compared with the same period in 2003, primarily due to decreased output and fuel costs at the Stony Brook generating facility in which we have an 8.8 percent joint ownership interest, and decreases in output and fuel costs used to operate our other peak generation facilities.

The cost of power that we purchased from other companies decreased $15.3 million or 21.1 percent in the first half of 2004 compared with the same period in 2003, primarily due to a $25.9 million decrease in purchases from Morgan Stanley, that was partially offset by increased expenses to replace the decreased output at the ENVY plant during outages and to supply increased retail sales to customers.

OTHER OPERATING EXPENSES

Other operating expenses increased $731,000 or 20.0 percent in the second quarter of 2004 compared with the same period in 2003 due to increased administrative and general, customer service, and distribution expenses caused by benefit and governance expenses. Other operating expenses increased $801,000 or 10.1 percent in the first half of 2004 compared with the same period in 2003 for the same reasons. We expect other operating expenses to grow by less than 10 percent by fiscal year end, when compared with 2003.

TRANSMISSION EXPENSES

Transmission expenses increased by approximately $539,000 or 15.4 percent for the three months ended June 30, 2004 compared with the same period in 2003, due to an increase in VELCO's debt service and other expenses for expanded Vermont transmission facilities.

Transmission expenses increased by approximately $192,000 or 2.5 percent for the six months ended June 30, 2004 compared with the same period in 2003 for the same reasons.

The ISO New England (ISO-NE") was created to manage the operations of the New England Power Pool ("NEPOOL"), effective May 1, 1999. ISO-NE operates a market for all New England states for purchasers and sellers of electricity in the deregulated wholesale energy markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold.

During 2002, the Federal Energy Regulatory Commission ("FERC") accepted ISO-NE's request to implement a Standard Market Design ("SMD") governing wholesale energy sales in New England. ISO-NE implemented its SMD plan on March 1, 2003. SMD includes a system of locational marginal pricing of energy, under which prices are determined by zone, and based in part on transmission congestion experienced in each zone. Currently, the State of Vermont constitutes a single zone under the plan, although pricing may eventually be determined on a more localized ("nodal") basis. ISO-NE and NEPOOL have committed to facilitation of a stakeholder process to examine alternative pricing options, including alternatives to nodal pricing, and to file their report with FERC in July 2004. On July 1, 2004, ISO-NE filed its report concluding that the existing load zones for energy pricing should not be modified at this time because energy prices within these load zones, including Vermont, are relatively uniform. ISO-NE did note, however that the load zones should and will be reviewed at least every two years, or upon the introduction of a significant change in circumstances, i.e., the implementation of a new market, a substantial physical change to the NEPOOL system, or at the direction of the FERC. We believe that nodal pricing could result in a material adverse impact on our power supply and/or transmission costs, if adopted, as long as the transmission facilities in Northwestern Vermont are constrained.

On October 31, 2003, ISO-NE, together with New England's principal transmission system owners, including VELCO, filed a request for designation of ISO-NE as a regional transmission organization for New England ("RTO-NE"). On March 24, 2004, the FERC conditionally approved ISO-NE's designation as an RTO. ISO-NE will continue to perform all of its current responsibilities and will also become the transmission provider for the New England region, acquiring operational authority over daily management of the transmission system. Also on

October 31, 2003, certain transmission owners in New England, including the Company, reached an agreement to submit a tariff, agreements and other documents to the FERC to include costs associated with certain transmission facilities, known as the Highgate Facilities, of which the Company is a part owner, in region-wide rates as set forth in the RTO-NE proposal. The Company and other transmission owners are currently working with ISO-NE to make operating arrangements in advance of making a filing with the FERC.

VELCO, the owner and operator of Vermont's principal electric transmission system assets, has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. We own approximately 29 percent of VELCO. The proposed Northwest Reliability Project must be approved by the VPSB. Several Vermont municipalities, citizen groups and individuals have intervened in the VPSB proceedings to oppose or request modifications to the project. If approved, the project is estimated to cost approximately $130 million through 2007. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment. The Company plans to invest approximately $20 million in VELCO to support this and other transmission projects through 2007. Under current NEPOOL and ISO-NE rules, which require qualifying large transmission project costs to be shared among all New England utilities, most of the costs of the Northwest Reliability Project will be allocated throughout the New England region, with Vermont utilities responsible for approximately five percent of allocated costs.

In August 2003, a coalition of New England public utility commissions and other parties challenged the NEPOOL and ISO-NE transmission cost allocation rules. On December 18, 2003, FERC rejected this challenge. FERC's order is subject to pending requests for rehearing and has been appealed to the US Court of Appeals for the D.C. Circuit. If the current transmission cost allocation rules are modified or eliminated, Vermont utilities, including the Company, could be required to bear a greater proportion, and potentially all, of the cost of the Northwest Reliability Project.

MAINTENANCE EXPENSES

Maintenance expenses increased $275,000 or 12.8 percent for the three months ended June 30, 2004 compared with the same period in 2003, primarily due to an increase in scheduled maintenance on distribution and hydro facilities. The Company is increasing expenditures by approximately $600,000 for tree clearing in rights of way to improve system reliability during 2004. Maintenance expenses increased $188,000 or 4.2 percent for the six months ended June 30, 2004 compared with the same period in 2003 for the same reasons.

DEPRECIATION AND AMORTIZATION EXPENSES

Depreciation and amortization expenses for the quarter ended June 30, 2004 increased $79,000 or 2.3 percent compared with the same period in 2003, reflecting an increase in the depreciation of utility plant, offset by a decrease in the amortization of demand side management assets. Depreciation and amortization expenses increased $21,000 or 0.3 percent for the six months ended June 30, 2004 compared with the same period in 2003 for the same reasons.

TAXES OTHER THAN INCOME TAXES

Other tax expense for the second quarter of 2004 decreased by $113,000 or 6.2 percent compared with the same period in 2003 due to reductions in property taxes.

Other tax expense for the first six months of 2004 decreased by $230,000 or 6.2 percent compared with the same period in 2003 due to reductions in property taxes.

INCOME TAXES

Income taxes increased $246,000 or 45.8 percent in the second quarter of 2004 compared with the same period in 2003 due to an increase in pretax book income from operations.

Income taxes increased $174,000 or 5.9 percent in the first half of 2004 compared with the same period in 2003 for the same reason.

OTHER INCOME

Other income decreased $181,000 or 38.4 percent during the three months ended June 30, 2004 compared with the same period in 2003, primarily due to decreases in earnings of Vermont Yankee and VELCO. The Vermont Yankee decrease in earnings was caused by a decrease in investments following a return of capital to the Company arising from the sale of the Vermont Yankee nuclear plant to ENVY. VELCO's earnings declined due to increases in debt service expense.

Other income decreased by $110,000 or 10.1 percent in first half of 2004 when compared with the same period in 2003, for the same reasons, partially offset by the 2003 receipt of insurance proceeds.

INTEREST CHARGES

Interest charges decreased $136,000 or 7.6 percent in the second quarter of 2004 compared with the same period in 2003, due to a decrease in long-term debt balances arising from the maturity of $8.0 million first mortgage bonds in December 2003.

Interest charges decreased $300,000 or 8.4 percent in the first half of 2004 compared with the same period in 2003, for the same reason.

LIQUIDITY AND CAPITAL RESOURCES

In the six months ended June 30, 2004, we spent $9.2 million principally for expansion and improvements of our transmission, distribution and generation plant, and environmental expenditures. We expect to spend approximately $12.4 million during the remainder of 2004, principally for improvements to transmission, distribution and generation plant, and environmental expenditures.

During June 2004, the Company negotiated a 364-day revolving credit agreement (the "Fleet-Sovereign Agreement") with Fleet Financial Services ("Fleet") joined by Sovereign Bank. The Fleet-Sovereign Agreement is for $30.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was no balance outstanding on the Fleet-Sovereign Agreement at June 30, 2004. The Fleet-Sovereign Agreement expires June 15, 2005.

The annual dividend was $0.76 per share for the year ended December 31, 2003. On February 9, 2004, the annual dividend rate was increased from $0.76 per share to $0.88 per share, a payout ratio of approximately 44 percent based on 2003 earnings. The Company expects to increase the dividend on a consistent basis in the first quarter of each year until the payout ratio falls between 50 percent and 70 percent of anticipated earnings. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles.

The credit ratings of the Company's first mortgage bonds at June 30, 2004 were:

	Fitch	Moody's	Standard & Poor's
First mortgage bonds	BBB+	Baa1	BBB

Moody's affirmed the Company's senior secured debt rating at Baa1, with a stable outlook on June 18, 2004.

Fitch Ratings affirmed the ratings of the Company's first mortgage bonds at BBB+, with a stable outlook during August 2003; and

Standard and Poor's Ratings Services affirmed its BBB rating of the Company's senior secured debt, with a stable outlook during August 2003.

In the event of a change in the Company's first mortgage bond credit rating to below investment grade, scheduled payments under the Company's first mortgage bonds would not be affected. Such a change would require the Company to post what would currently amount to a $4.3 million bond under our remediation agreement with the EPA regarding the Pine Street Barge Canal site. The Morgan Stanley Contract requires credit assurances if the Company's first mortgage bond credit ratings are lowered to below investment grade by any two of the three credit rating agencies listed above.

OFF-BALANCE SHEET ARRANGEMENTS - The Company does not use off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments" and "Power Supply Expenses." We also own an equity interest in VELCO, which requires the Company to contribute capital when required and to pay a portion of VELCO's operating costs, including its debt service costs.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK AND OTHER RISK FACTORS

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

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

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

DEFINED BENEFIT PLANS

Due to sharp declines in the equity markets during 2001 and 2002, the value of assets held in trusts to satisfy the Company's defined benefit plan obligations has decreased. The Company's defined benefit plan assets are primarily made up of public equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased defined benefit plan costs in future periods.

The Company's funding policy is to make voluntary contributions to its defined benefit plans before ERISA or Pension Benefit Guaranty Corporation requirements mandate such contributions under minimum funding rules, and so long as the Company's liquidity needs do not preclude such investments. The Company made pension plan contributions totaling $4.5 million between September 1, 2002 and December 31, 2003. The Company intends to contribute between $2.0 million and $3.0 million to its defined benefit plans by December 31, 2004.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum pension liability of $2.4 million, net of applicable income taxes. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income

("OCI"). Favorable pension plan investment returns during 2003 reduced the OCI charge and related net liability by $587,000 at December 31, 2003. The 2002 OCI charge and the 2003 OCI benefit had no effect on net income for either year.

MARKET RISK

We have created a power supply portfolio that meets approximately 90 percent of our estimated customer demand ("load") requirements through 2006. Our power supply contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices. The Company's power supply contracts are described in more detail in Part I, Item 1, No. 3 above under the heading "Power Contract Commitments."

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Implementation of New England's wholesale market for electricity has increased volatility of wholesale power prices. Periods frequently occur when weather, availability of power supply resources and other factors cause significant differences between customer demand and electricity supply. Because electricity cannot be stored, in these situations the Company must buy or sell the difference into a marketplace that has experienced volatile energy prices. Volatility and market price trends also make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief.

The Company has established a risk management program designed to stabilize cash flow and earnings by minimizing power supply risks, including counter party credit risk. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and transmission congestion rights. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Some of these transactions present the risk of potential losses from adverse changes in commodity prices. Our risk management policy specifies risk measures, the amount of tolerable risk exposure, and authorization limits for transactions. Our principal power supply contract counter-parties and generators, Hydro Quebec, Entergy Nuclear Vermont Yankee, LLC and Morgan Stanley Capital Group, Inc., all currently have investment grade credit ratings.

The Company has a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") that is used to hedge our power supply costs against increases in fossil fuel prices. Morgan Stanley purchases approximately 15 percent of the Company's power supply resources at index prices for fossil fuel resources and specified prices for contracted resources and then sells power to the Company at a fixed rate to serve pre-established load requirements. This contract, along with other power supply commitments, allows us to fix the cost of most of our power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133") and is effective through December 31, 2006. Management has estimated the fair value of the future net benefit of this arrangement at June 30, 2004, is approximately $12.2 million.

We currently have an arrangement that grants Hydro Quebec an option (the "9701 arrangement") to call power at prices that are expected to be below estimated future market rates. The 9701 arrangement is described in more detail below under the heading "Power Supply Expenses." 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, 2004, is approximately $24.6 million. We sometimes use forward contracts to hedge forecasted calls by Hydro Quebec under the 9701 arrangement.

The table below presents the Company's market risk of the Morgan Stanley and Hydro Quebec derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to approximately $882,000. Actual results may differ materially from the table illustration. Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred.

Commodity Price Risk	Fair Value(Cost) (in thousands)	At June 30, 2004 Market Risk
Morgan Stanley Contract	$ 12,210	$ 2,310
9701 Arrangement. . . .	(24,560)	(3,192)
	(12,350)	(882)

NEW ACCOUNTING STANDARDS

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

EFFECTS OF INFLATION

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

ITEM 4. CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, the Company carried out an evaluation, with the participation of the Company's management, including the Company's President and Chief Executive Officer, and Chief Financial Officer and Treasurer, of the effectiveness of the Company's disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, the Company's President and Chief Executive Officer, and Chief Financial Officer and Treasurer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company (including its consolidated subsidiaries) required to be included in the Company's periodic SEC filings. There has been no change in the Company's internal control over financial reporting during the three and six months ended June 30, 2004 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

GREEN MOUNTAIN POWER CORPORATION

JUNE 30, 2004

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 meeting of shareholders held on May 20, 2004, there were 5,064,188 shares of common stock outstanding and entitled to vote, of which 4,371,178 were represented in person or by proxy. The following matters were submitted to a vote of the Company's shareholders at its annual meeting with the voting results designated below each such matter:

1. Ratification of the appointment of Deloitte and Touche LLP as the independent auditors for the Company for 2004 with 4,284,514 votes for, 59,709 votes against, and 29,655 votes abstaining.

2. Approval of the 2004 Stock Incentive Plan with 2,481,196 votes for, 904,638 votes against, 69,648 vote abstentions, and 915,696 broker non-votes votes.

3. Approval of the proposal to amend and restate the Company's Restated Articles of Association with 2,969,544 votes for, 412,251 votes against, 73,687 votes abstaining, and 915,696 broker non-votes.

4. Election of the nominees listed below as Directors of this Company for a term of one year, with votes cast as indicated.

Directors	Votes For	Votes Against or Withheld
Elizabeth A. Bankowski	3,915,625	455,553
Nordahl L. Brue, Chair	4,096,180	274,998
William H. Bruett. . .	4,043,870	327,308
Merrill O. Burns . . .	3,991,591	379,587
David R. Coates. . . .	4,073,849	297,329
Christopher L. Dutton.	4,081,553	289,625
Kathleen C. Hoyt . . .	3,961,988	409,190
Euclid A. Irving . . .	4,058,413	312,765
Marc A. vanderHeyden .	3,984,256	386,922

There were no broker non-votes with respect to the election of directors.

ITEM 5. Other Information NONE

ITEM 6.
(A) EXHIBITS

Exhibit 3-A, Amended and Restated Articles of Incorporation.

Exhibit 10-d-64, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Elizabeth A. Bankowski as of July 19, 2004.
Exhibit 10-d-65, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Nordahl L. Brue as of July 19, 2004.

Exhibit 10-d-66, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director William H. Bruett as of July 19, 2004.

Exhibit 10-d-67, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Merrill O. Burns as of July 19, 2004.

Exhibit 10-d-68, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director David R. Coates as of July 19, 2004.

Exhibit 10-d-69, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Kathleen C. Hoyt as of July 19, 2004.

Exhibit 10-d-70, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Euclid A. Irving as of July 19, 2004.

Exhibit 10-d-71, Director's Deferred Stock Unit Agreement for the grant of deferred stock units to Director Marc A. vanderHeyden as of July 19, 2004.

Exhibit 31.1, Certification by Christopher L. Dutton, President and Chief Executive Officer of Green Mountain Power Corporation, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2, Certification by Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer of Green Mountain Power Corporation, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1, Certification by Christopher L. Dutton, President and Chief Executive Officer of Green Mountain Power Corporation, and Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer of Green Mountain Power Corporation, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(B) REPORTS ON FORM 8-K

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

A report on Form 8-K (Item 12), dated May 4, 2004, was furnished to report that the Company issued a press release regarding its earnings for the quarter ended March 31, 2004 (not incorporated by reference).

A report on Form 8-K (Items 5 and 7), dated May 14, 2004, was filed to report that the Company issued a press release regarding certain corporate governance matters.

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 6, 2004

/s/ Christopher L. Dutton
Christopher L. Dutton, Chief Executive Officer and President

Date: August 6, 2004

/s/ Robert J. Griffin
Robert J. Griffin, Chief Financial Officer Vice President and Treasurer