GREEN MOUNTAIN POWER CORP
Form 10-Q
November 09, 2005

United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2005

or

o 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, Vermont**	**05446**
(Address of Principal Executive Offices)	(Zip Code)

(802) 864-5731
Registrant's telephone number, including area code

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 o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes x No o

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 October 31, 2005
$3.33 1/3 Par Value	5,224,070

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," “forecast,” "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 Nine months Ended September 30, 2005 and 2004

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

GREEN MOUNTAIN POWER CORPORATION	Unaudited							
Consolidated Comparative Income Statements	Three Months Ended				Nine Months Ended			
	September 30				September 30			
In thousands, except per share data	2005		2004		2005		2004	
Operating revenues								
Retail Revenues	$	57,584	$	51,224	$	162,874	$	154,838
Wholesale Revenues		6,740		4,443		14,586		19,220
Total operating revenues		64,324		55,667		177,460		174,058
Operating expenses								
Power Supply								
Vermont Yankee Nuclear Power Corporation		8,375		8,602		25,837		23,223
Company-owned generation		1,905		1,650		4,336		5,095
Purchases from others		30,125		23,814		77,739		80,916
Other operating		6,968		5,089		17,124		14,518
Transmission		4,077		3,479		12,707		11,217
Maintenance		2,842		2,451		7,871		7,147
Depreciation and amortization		3,770		3,479		11,299		10,451
Taxes other than income		1,530		1,361		4,914		4,853
Income taxes		893		1,147		3,826		4,246
Total operating expenses		60,485		51,072		165,653		161,666
Operating income		3,839		4,595		11,807		12,392
Other income								
Equity in earnings of affiliates and non-utility operations		360		410		1,201		943
Allowance for equity funds used during construction		8		112		22		336
Other income (deductions), net		3		(122)		(70)		112
Total other income		371		400		1,153		1,391
Interest charges								
Long-term debt		1,633		1,633		4,901		4,900
Other interest		57		41		173		181
Allowance for borrowed funds used during construction		(4)		(71)		(14)		(213)
Total interest charges		1,686		1,603		5,060		4,868
Income from continuing operations		2,524		3,392		7,900		8,915
Income (Loss) from discontinued operations, net		18		(2)		2		(9)
Net income applicable to common stock	$	2,542	$	3,390	$	7,902	$	8,906

	Unaudited							
Consolidated Statements of Comprehensive Income	Three Months Ended				Nine Months Ended			
	September 30				September 30			
	2005		2004		2005		2004	
Net income	$	2,542	$	3,390	$	7,902	$	8,906

Other comprehensive income, net of tax		-		-		-		-
Comprehensive income	$	2,542	$	3,390	$	7,902	$	8,906
Basic earnings per share	$	0.49	$	0.67	$	1.52	$	1.76
Diluted earnings per share	$	0.48	$	0.65	$	1.50	$	1.70
Cash dividends declared per share	$	0.25	$	0.22	$	0.75	$	0.66
Weighted average common shares outstanding-basic		5,208		5,089		5,185		5,068
Weighted average common shares outstanding-diluted		5,301		5,251		5,284		5,238

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

	Unaudited	
GREEN MOUNTAIN POWER CORPORATION	**Nine Months Ended**	
Consolidated Statements of Cash Flows	**September 30**	
In thousands	**2005**	**2004**
Operating Activities		
Income from continuing operations	$ 7,900	$ 8,915
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	11,299	10,451
Equity in undistributed earnings of associated companies	(1,107)	(648)
Dividends from associated companies	916	545
Allowance for funds used during construction	(36)	(549)
Amortization of deferred purchased power costs	1,841	239
Deferred income tax (benefit) expense, net of investment tax credit amortization	(1,175)	1,424
Deferred purchased power costs	(2,023)	(1,435)
Rate levelization liability and other deferred revenues	1,284	(1,876)
Environmental and conservation deferrals, net	(268)	(1,250)
Cash in advance of construction	2,160	1,495
Gain on sale of property	-	(242)
Amortization of Pine Street	255	-
Deferred and share-based compensation	780	522
Changes in:		
Accounts receivable and accrued utility revenues	(1,390)	2,522
Prepayments, fuel and other current assets	686	(145)
Accounts payable and other current liabilities	285	2,056
Income taxes payable and receivable	1,012	(1,416)
Other	(1,140)	831
Net cash provided by continuing operations	21,279	21,439
Net loss from discontinued operations	2	(9)
Net cash provided by operating activities	21,281	21,430
Investing Activities		
Construction expenditures	(14,281)	(14,626)
Restriction of cash for renewable energy investments	(969)	(352)
Return of capital from associated companies	166	220
Investment in nonutility property	(156)	(297)
Net cash used in investing activities	(15,240)	(15,055)
Financing Activities		
Issuance of common stock	946	1,368
Short-term debt	(3,000)	(500)
Cash dividends	(3,898)	(3,352)
Net cash used in financing activities	(5,952)	(2,484)
Net increase in cash and cash equivalents	89	3,891
Cash and cash equivalents at beginning of period	1,720	786
Cash and cash equivalents at end of period	$ 1,809	$ 4,677
Supplemental Disclosure of Cash Flow Information		
Cash paid for:		
Interest	$ 4,362	$ 4,383
Income taxes	3,073	2,897
Non-cash construction additions	567	536

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

GREEN MOUNTAIN POWER CORPORATION			
Consolidated Balance Sheets	**Unaudited**		
	September 30		**December 31**
In thousands	**2005**	**2004**	**2004**
ASSETS			
Utility plant			
Utility plant, at original cost	$ 346,614	$ 327,908	$ 339,269
Less accumulated depreciation	126,800	120,438	119,633
Utility plant, net of accumulated depreciation	219,814	207,470	219,636
Property under capital lease	4,731	5,162	4,731
Construction work in progress	10,656	17,493	8,345
Total utility plant, net	235,201	230,125	232,712
Other investments			
Associated companies, at equity	10,089	5,779	10,179
Other investments	10,454	8,731	8,780
Total other investments	20,543	14,510	18,959
Current assets			
Cash and cash equivalents	1,809	4,677	1,720
Accounts receivable, less allowance for doubtful accounts of $466, $747 and $621	20,800	16,664	18,216
Accrued utility revenues	5,769	4,874	6,964
Fuel, materials and supplies, average cost	4,726	4,463	4,848
Prepayments	1,188	1,997	1,674
Income tax receivable	695	422	1,717
Other	244	893	323
Total current assets	35,231	33,990	35,462
Deferred charges			
Demand side management programs	6,199	7,144	7,293
Purchased power costs	2,540	3,170	2,322
Pine Street Barge Canal	12,996	12,954	13,250
Net power supply deferral	7,765	7,114	12,085
Power supply derivative asset	22,826	11,511	10,736
Other regulatory assets	6,612	7,578	6,932
Other deferred charges	832	1,434	1,113
Total deferred charges	59,770	50,905	53,731
Non-utility			
Property and equipment	246	248	247
Other assets	431	542	508
Total non-utility assets	677	790	755
Total assets	$ 351,422	$ 330,320	$ 341,619

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

GREEN MOUNTAIN POWER CORPORATION						
Consolidated Balance Sheets		**Unaudited**				
		September 30				**December 31**
In thousands except share data		**2005**		**2004**		**2004**
CAPITALIZATION AND LIABILITIES						
Capitalization						
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 6,050,209, 5,930,126 and 5,968,118)	$	20,167	$	19,767	$	19,894
Additional paid-in capital		80,437		77,741		78,852
Retained earnings		33,893		28,340		29,889
Accumulated other comprehensive income		(2,353)		(1,787)		(2,353)
Treasury stock, at cost (827,639 shares)		(16,701)		(16,701)		(16,701)
Total common stock equity		115,443		107,360		109,581
Long-term debt, less current maturities		93,000		93,000		93,000
Total capitalization		208,443		200,360		202,581
Capital lease obligation		4,364		4,967		4,493
Current liabilities						
Short-term debt		-		-		3,000
Accounts payable, trade and accrued liabilities		9,467		12,609		9,437
Accounts payable to associated companies		5,545		3,212		7,391
Deferred revenues		-		1,351		-
Accrued taxes		1,353		-		1,290
Customer deposits		936		954		1,063
Interest accrued		1,788		1,769		1,136
Other		1,730		1,585		1,151
Total current liabilities		20,819		21,480		24,468
Deferred credits						
Power supply derivative liability		30,591		18,626		22,821
Accumulated deferred income taxes		31,186		31,533		32,223
Unamortized investment tax credits		2,351		2,641		2,564
Pine Street Barge Canal cleanup liability		6,190		6,106		6,458
Accumulated cost of removal		21,121		19,618		19,806
Deferred compensation		8,740		8,625		8,872
Other regulatory liabilities		4,858		4,403		4,012
Other deferred liabilities		10,506		9,425		11,150
Total deferred credits		115,543		100,977		107,906
COMMITMENTS AND CONTINGENCIES, Note 3						
Non-utility						
Net liabilities of discontinued segment		2,253		2,536		2,171
Total non-utility liabilities		2,253		2,536		2,171
Total capitalization and liabilities	$	351,422	$	330,320	$	341,619
The accompanying notes are an integral part of these consolidated financial statements.						

	Unaudited			
Consolidated Statements of Retained Earnings	**Three Months Ended September 30**		**Nine Months Ended September 30**	
In thousands	**2005**	**2004**	**2005**	**2004**
Balance - beginning of period	$ 32,657	$ 26,071	$ 29,889	$ 22,786
Net Income	2,542	3,390	7,902	8,906
Other adjustments	-	-	-	-
Cash Dividends-common stock	(1,306)	(1,121)	(3,898)	(3,352)
Balance - end of period	$ 33,893	$ 28,340	$ 33,893	$ 28,340

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

GREEN MOUNTAIN POWER CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2005

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 2004 filed on Form 10-K, are adequate to make the information presented not misleading. 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 such estimates.

Regulatory Accounting. The Company's utility operations, including accounting records, rates, operations and certain other practices of its electric utility business, are subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC") and the Vermont Public Service Board ("VPSB"). The Vermont Department of Public Service ("DPS" or the "Department") is the public advocate for utility customers.

The accompanying consolidated financial statements conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards No. ("SFAS") 71 ("SFAS 71"), "Accounting for Certain Types of Regulation." Under SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Regulators may also require benefits to be deferred as regulatory liabilities, pending future rate proceedings.

Revenues. The VPSB 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 pursuant to VPSB order (the "Deferred Revenues"), of which $3.0 million, was recognized during 2004. At December 31, 2004, the Company had recognized all the Deferred Revenues.

Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, the Company makes various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix (residential, small commercial and industrial), and 4) average retail customer pricing rates.

The Company recognizes revenues from sales of utility construction and other services in retail revenues. To the extent that these revenues arise under long-term contracts, the Company records revenues and net income using the percentage of contract completion method.

Benefit Plans. The Company sponsors several qualified and nonqualified pension plans and other post-employment benefit plans covering current and former employees who meet certain eligibility criteria. The assumptions used to calculate the cost and obligations associated with these plans are determined on January 1 for the upcoming year.

These assumptions are disclosed in the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2004 (the "Form 10-K"). The Company expects to contribute approximately $2.0 million to its benefit plans in 2005. During the nine months ended September 30, 2005, GMP contributed $1.5 million to its benefit plans.

Qualified Pension and Supplemental Pension Plans	Three Months Ended September 30		Nine Months Ended September 30	
In thousands	2005	2004	2005	2004
Service cost	$ 256	$ 281	$ 768	$ 842
Interest cost	588	573	1,764	1,718
Expected return on plan assets	(603)	(571)	(1,809)	(1,714)
Amortization of prior service cost	52	51	156	154
Recognized net actuarial gain	55	67	165	200
Net periodic pension benefit cost	$ 348	$ 401	$ 1,044	$ 1,200

Other Postretirement Benefit Plan	Three Months Ended September 30		Nine Months Ended September 30	
In thousands	2005	2004	2005	2004
Service cost	$ 77	$ 84	$ 231	$ 251
Interest cost	267	291	801	874
Expected return on plan assets	(236)	(214)	(708)	(643)
Amortization of prior service cost	(59)	(60)	(177)	(179)
Amortization of the transition obligation	83	82	249	246
Recognized net actuarial gain	56	85	168	254
Net periodic other postretirement benefit cost	$ 188	$ 268	$ 564	$ 803

The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee pre-tax contributions up to 4 percent, and contributes an additional one-half percent each year made on a non-matching basis, of eligible compensation. The additional half percent contribution was added effective January 2004. The Company match is immediately vested. The Company's matching and non-matching contributions for the third quarter of 2005 and 2004 were $131,000 and $137,000, respectively. The Company's matching and non-matching contributions for the first nine months of 2005 and 2004 were $351,000 and $380,000, respectively.

Reclassification. The Company changed the classification of certain previously reported amounts in the accompanying balance sheet and cash flow statement as of September 30, 2004 to correct immaterial errors related to the accounting for income taxes. The effect of the changes was to decrease accumulated deferred income taxes by $4.0 million, increase other deferred credits by $3.4 million, and increase net liabilities of a discontinued segment by approximately $600,000. We reclassified certain items on the cash flow statement and the balance sheet at and for the nine months ended September 30, 2004 to provide additional detail and for consistent presentation with the current year.

Earnings Per Share. Basic earnings per share ("EPS") is calculated by dividing net income, by the weighted-average common shares outstanding for the period. Diluted EPS reflects the impact of the issuance of common shares for all potential dilutive common shares outstanding during the period, including stock options.

Reconciliation of income and shares used in	Three months ended	Nine months ended

computing fully diluted earnings per share	September 30		September 30	
In thousands	2005	2004	2005	2004
Net income applicable to common stock	$ 2,542	$ 3,390	$ 7,902	$ 8,906
Weighted average number of common shares-basic	5,208	5,089	5,185	5,068
Dilutive effect of stock options	93	162	99	170
Weighted average number of common shares-diluted	5,301	5,251	5,284	5,238

The Company adopted the prospective method of accounting for stock-based compensation under SFAS 148 beginning January 1, 2003. The information presented below has been determined as if the Company accounted for all past employee and director stock options under the fair value method.

	Three months ended		Nine Months Ended	
Pro-forma net income	September 30		September 30	
	2005	2004	2005	2004
In thousands, except per share amounts				
Net income reported	$ 2,542	$ 3,390	$ 7,902	$ 8,906
Pro-forma net income	2,542	3,370	7,901	8,845
Earnings per share				
As reported-basic	$ 0.49	$ 0.67	$ 1.52	$ 1.76
Pro-forma basic	0.49	0.66	1.52	1.75
As reported-diluted	0.48	0.65	1.50	1.70
Pro-forma diluted	0.48	0.64	1.50	1.69

Unregulated operations. Our wholly owned subsidiaries include GMP Real Estate Corporation and Green Mountain Power Investment Company ("GMPIC"). Green Mountain Resources, Inc. and Green Mountain Propane Gas Company Limited 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, are included in equity in earnings of affiliates and non-utility operations in the Other Income (Deductions) section of the Consolidated Statements of Income.

Discontinued Operations. The Company accounts for its wholly-owned subsidiary, Northern Water Resources, Inc. ("NWR"), as a discontinued operation. NWR's assets and liabilities consist primarily of deferred tax assets and liabilities relating to a number of investments that the company has discontinued, inactivated, sold in part or retains as passive minority interests. Remaining holdings include a minority equity investment in a wind project that usually, but not always, generates tax losses; a minority interest in a manufacturer of waste treatment equipment; and non-performing loans. Substantially all of NWR's investments have been written off, except for associated deferred tax amounts, net of applicable valuation allowances.

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 ("VYNPC")
Percent ownership: 33.6% common

Summarized unaudited financial information for VYNPC follows:

	Three Months Ended September 30		Nine Months Ended September 30	
In thousands	2005	2004	2005	2004
Gross Revenue	$ 41,918	$ 44,132	$ 125,227	$ 118,329
Net Income Applicable to Common Stock	169	130	511	401
Equity in Net Income	57	44	172	135
Amounts due to VYNPC at September 30	2,862	3,171	2,862	3,171

Entergy Nuclear Vermont Yankee, LLC ("ENVY"), the owner of the Vermont Yankee Nuclear Plant, has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. Current Vermont law requires ENVY to obtain approval of the Vermont State legislature, in addition to VPSB approval, to construct and use such dry fuel storage facilities. The Vermont legislature passed a bill in June 2005 allowing ENVY to apply for dry fuel storage permission from the VPSB. The bill was signed into law in June and ENVY subsequently applied for VPSB approval. VPSB hearings are expected to be conducted over an extended period of time.

If ENVY fails to obtain VPSB approval, ENVY could be required to shut down the Vermont Yankee plant. If the Vermont Yankee plant is shut down, we would have to acquire substitute base load power resources, comprising approximately 35 percent of our estimated total power supply needs. At currently projected market prices for 2006, we estimate the annual incremental cost (in excess of the projected costs of power under our power supply contract for output from the Vermont Yankee facility) would be approximately $56.8 million annually. Recovery of those increased costs in rates would require a rate increase of approximately 28 percent.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the Vermont Yankee plant resulted in a shutdown of the plant. The outage ended on July 7, 2004. In response to the Company's request, the VPSB issued a final accounting order allowing the Company to defer its incremental replacement power costs during the outage totaling approximately $500,000. The order also instructs the Company to apply any proceeds received under a Ratepayer Protection Proposal ("RPP") to reduce the balance of deferred replacement power costs.

The RPP was part of ENVY's request to uprate or increase the output of the Vermont Yankee plant that was approved by the VPSB, subject to certain conditions. The Nuclear Regulatory Commission has not yet approved Entergy’s application to uprate the plant. Under the RPP, we have indemnification rights to between approximately $550,000 and $1.6 million to recover uprate-related reductions in output for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years), depending on future wholesale energy market prices. The Company and ENVY dispute whether the fire was uprate-related, and therefore whether the associated outage is subject to indemnification under the RPP. The Company has petitioned the VPSB to resolve the dispute.

Vermont Electric Power Company, Inc. ("VELCO")
Percent ownership: 29.2% common
30.0% preferred

VELCO and its wholly-owned subsidiary, Vermont Electric Transmission Company, own and operate the transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. The Company plans to make capital investments of up to $32 million in VELCO through 2009 in support of various transmission projects, including a $4.6 million investment made in the last quarter of 2004.

Summarized unaudited financial information for VELCO is as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
In thousands	2005	2004	2005	2004
Gross Revenue	$ 7,248	$ 6,363	$ 22,754	$ 19,239
Net Income	739	779	2,213	1,397
Equity in Net Income	214	204	642	335
Amounts due to VELCO at June 30	2,682	20	2,682	20

The cost of transmission services charged by VELCO included in the Company's transmission expenses in the accompanying Consolidated Statements of Income amounted to $3.2 million and $10.3 million in the third quarter and first nine months of 2005, respectively, compared with $2.7 million and $8.9 million in the third quarter and first nine months of 2004, respectively.

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 our compliance with present environmental protection regulations, except as described below under the caption "Pine Street Barge Canal Superfund 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." We have estimated total future costs of the Company's future obligations under the consent decree to be approximately $6.2 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We previously recorded a regulatory asset of $13.2 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company's 2003 Rate Plan approved by the VPSB, the Company has begun 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 is expected to be allowed in future rates, without disallowance or adjustment, until fully amortized.

Rates - Management believes that fair regulatory treatment, including adequate and timely rate relief, is required to maintain the Company's financial strength**.**

Retail Rate Cases - On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed 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 remained 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. We submitted a cost of service schedule supporting the 1.9 percent rate increase for 2005, and in accordance with the plan, the increase became effective on January 1, 2005. On November 1, 2005, we submitted a cost of service schedule supporting the 0.9 percent rate increase for 2006 in accordance with the plan. The rate increase is subject to VPSB approval. The VPSB retains the discretion to open an investigation of the Company's rates at any time, at the request of the DPS, the request of ratepayers, or on its own volition. Certain ratepayers requested the VPSB to open such an investigation in connection with the Company's 1.9 percent rate increase for 2005. The VPSB granted the request in December 2004, and then, at our request, closed and terminated its investigation in January 2005, with no adverse impact on the Company's rates.

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

· The Company's annual allowed return on equity is 10.5 percent for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. The Company's earnings did not exceed the cap in 2004. If earnings exceed the cap in 2005 or 2006, they will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

· The Company carried forward into 2004 $3.0 million in Deferred Revenues remaining at December 31, 2003, from a previous VPSB order. These revenues were applied in 2004 to offset increased costs.

· The Company has begun to 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.

Other Regulatory Matters

On March 29, 2005, the VPSB issued its Order in a retail rate proceeding filed by Central Vermont Public Service Corporation ("CVPS"), the largest Vermont electric utility. The CVPS Order included a determination that CVPS should calculate its utility earnings under a voluntary earnings cap, to which CVPS had previously agreed, using a new ratemaking methodology. The VPSB required CVPS to recalculate its earnings cap retroactively to 2001, after removing expenses and assets that would not be included in its cost of service or rate base. Under the 2003 Rate Plan, GMP calculated its earnings cap in 2003 in the same manner as CVPS. GMP does not have substantial net assets on its balance sheet that would normally be excluded from rate base. We have also calculated, and submitted to the DPS, earnings cap calculations for 2003 and 2004 applying the methodology ordered by the VPSB in the CVPS rate case. The calculations indicate that the Company did not exceed its earnings cap in 2003 and 2004 under either calculation method.

The CVPS Order also provided CVPS with an allowed rate of return of 10 percent as compared with the 10.5 percent return on equity allowed in our 2003 Rate Plan. The CVPS Order found that CVPS's risk profile differs from GMP's in several ways, including the absence of significant customer concentration risk, cost of capital and other considerations.

Power Supply Risks and Contingencies

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, which together supply approximately 70 percent of our retail load. The Company has a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"), that supplies approximately 16 percent of our load.

We expect approximately 90 percent of our estimated 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.

There are uncertainties regarding risks of delivery under various contracts that the Company relies upon to satisfy customer demand for electricity. If the Company's entitlements for electricity are not realized due to delivery risks, the exercise of options that reduce our entitlements under certain contracts, or for other reasons, then the Company would purchase replacement energy and be subject to volatile energy prices that exist in the wholesale markets that could materially affect our operating results and financial condition.

The Company remains exposed to wholesale energy prices for approximately 10 percent of its load. Wholesale energy price volatility can also adversely impact margins on incremental sales. Energy price risk remains one of the Company's most significant risks and can have a material adverse effect on the Company's operating results and financial condition.
Our outage risks are generally a function of how much energy we receive from a particular source, the price of energy received from that source, whether the energy is unrelated to any specific operating plant (low-risk system power) or is dependent upon a particular power plant operating (high-risk), and the dependability of the transmission delivery system for that source. Counterparty credit quality also impacts risk. The Company's most significant power supply contract counterparties and certain associated risk attributes are summarized in the following table:

Contract	**Counterparty**	**Investment Grade**	**System Power or Plant**	**Approximate Percent Load**	**Approximate Amount $ Per MWh**
VYNPC	ENVY (through VYNPC)	No	VY Plant	35 - 40%	$40
VJO	Hydro Quebec	Yes	System Power	30 - 35%	$70
Morgan Stanley	Morgan Stanley	Yes	System Power	16%	Confidential*

**Morgan Stanley Contract terms are subject to a confidentiality agreement.*

See further discussion of the Company's power supply commitments and risk under Part I, Item 3, Management's Discussion and Analysis.

Competition
The Town of Rockingham, Vermont, located in the southeastern portion of our service territory, had an option to purchase a hydro-electric facility partially located in the town (the "Bellows Falls facility"). On July 12, 2005, Rockingham voters rejected their option to purchase the Bellows Falls facility. A group of residents petitioned the Town for a re-vote on the issue. Upon re-vote, Rockingham voters again rejected their option to purchase the Bellows Falls facility, effectively ending negotiations between the Company and the Town to permit the Town to be responsible for its own power supply needs.

Other Legal Matters
In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydro-electric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company received VPSB approval for, and has made additional dam improvements at, the facility. The VPSB had pending a regulatory proceeding to determine whether to impose regulatory penalties in connection with the 1995 dam improvements. The Company and the DPS have stipulated to a penalty amount of $50,000. The stipulation was approved by the VPSB on July 20, 2005 and the stipulated $50,000 penalty amount has been paid. In addition, numerous owners of shoreline

property on Joe's Pond have filed a lawsuit in Vermont superior court seeking damages for property damage allegedly caused by the Company's negligent conduct in making dam improvements and operating the dam facilities. The Company is defending against these claims. The Company does not expect the litigation to result in a material adverse effect on its operating results or financial condition.

4. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments primarily to reduce power supply risk. The Company does not hold derivative trading positions. The Company has continued to record expense related to derivatives in the period settled consistent with an accounting order issued by the VPSB which allows for changes in fair values of derivatives to be recorded as regulatory assets or liabilities.

SFAS 133, as amended, 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.

We currently have an agreement (the "9701 agreement") that grants Hydro Quebec an option to call power at prices below current and estimated future market rates. This agreement is a derivative and is effective through 2015.

The Morgan Stanley Contract is used to hedge against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative and expires December 31, 2006.

At September 30, 2005, the Company had a power supply derivative liability recorded in deferred credits of $30.6 million reflecting the fair value of the 9701 agreement, and a power supply derivative asset of $22.8 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $7.8 million is also recorded in deferred charges. At December 31, 2004, the Company had a liability of $22.8 million, reflecting the fair value of the 9701 agreement, and an asset of $10.7 million, reflecting the fair value of the Morgan Stanley Contract. A corresponding net regulatory asset of $12.1 million was also recorded. The Company believes that the net regulatory asset is probable of recovery in future rates. The net regulatory asset is based on current estimates of future market prices that are likely to change by material amounts.

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.

5. 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 subsidiaries (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.

6. NEW ACCOUNTING STANDARDS

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") which requires employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Act. The effect of the federal subsidy under the Act, accounted for as an actuarial gain, resulted in a reduction of $3.5 million to the Company's accumulated postretirement benefit obligation at December 31, 2004, and is expected to reduce net periodic cost by approximately $368,000 in 2005.

In December 2004, the FASB issued a revision to SFAS No. 123R, "Share-Based Payments," which replaces SFAS No. 123, "Accounting for Stock-Based Compensation." The revision determines how the Company will measure the cost of employee services received in exchange for share-based payments. The cost of share-based payments will be based on the grant date fair value of the award. The guidance is effective for the Company as of the beginning of 2006. The Company has not yet determined what the impact of this new standard will be on its financial position or results of operations.

In December 2004, the FASB issued FASB Staff Position 109-1 ("FSP 109-1"), which was effective upon issuance, to provide guidance of the application of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to the provision within the American Jobs Creation Act of 2004 ("Jobs Act") that provides a tax deduction on qualified production activities. The Jobs Act includes a tax deduction of up to 9 percent (when fully phased-in) of the lesser of (a) "qualified production activities income," as defined in the Jobs Act, or (b) taxable income (after the deduction for the utilization of any net operating loss carryforwards). The tax deduction is limited to 50 percent of W-2 wages paid by the taxpayer. FSP 109-1 clarifies that the manufacturer's deduction provided for under the Jobs Act should be accounted for as a special deduction in accordance with SFAS 109 and not as a tax rate reduction. The adoption of FSB 109-1 had no impact on the Company's financial statements in 2004. The Company estimates that in 2005 the deduction will approximate $80,000.

In March 2005, the FASB issued FASB Interpretation No. 47 ("FIN 47") Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB 143, Accounting for Asset Retirement Obligations. FIN 47 clarifies that the term *conditional asset retirement obligation* as used in FASB 143 refers to a legal obligation to perform an asset retirement activity in which the timing or method of settlement is conditional on a future event that may or may not be within the control of the reporting entity. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value can be reasonably estimated, and should be recognized when incurred. FIN 47 is effective for the Company in 2005. The Company has not yet determined what the impact of this new standard will be on its financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, “Accounting Changes and Error Corrections”, a replacement of APB Opinion No. 20 and FASB Statement No. 3. This statement applies to voluntary changes in accounting principle and requires retrospective application to prior period final statements, unless impracticable to determine. The statement is a result of a broader effort by the FASB to improve comparability of financial reporting between US and international accounting standards. The Company does not expect this standard to have any material impact on its results of operations or its financial condition.

GREEN MOUNTAIN POWER CORPORATION
Part I — ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
September 30, 2005

Executive Overview -- Green Mountain Power Corporation (the "Company") generates most of its earnings from retail electricity sales. Our retail electricity sales typically grow at an average annual rate of between one and two percent, about average for most electric utility companies in New England. Wholesale revenues have relatively minor impact on our operating results and financial condition because our power supply resources approximate expected customer demand. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

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 order to attract capital. In December 2003, the Company received approval from the VPSB of a new rate plan covering the period 2003 through 2006 (the "2003 Rate Plan"). In accordance with the 2003 Rate Plan, the VPSB approved, and the Company implemented, a 1.9 percent rate increase, effective January 1, 2005. The 2003 Rate Plan also provides for an additional 0.9 percent increase effective January 1, 2006, subject to the Company's need for such increase. The 2003 Rate Plan is summarized in more detail in Part I, Item 1, Note 3 "Retail Rate Cases".

The Company expects to request an accounting order to defer incremental power supply and transmission costs caused by an extraordinary and rapid increase in energy prices that is forecasted to adversely affect costs in 2006 by a material amount, absent deferral. Much of the recent increase in energy prices was caused by hurricanes Katrina and Rita, which interrupted natural gas and oil supplies. VPSB approval is required to permit the Company to defer these costs. The estimated deferral amount is expected to range between $4 and $8 million and could change by a material amount based on energy prices and other factors. The Company will not seek to defer unanticipated higher energy expenses incurred in 2005.

The VPSB's January 2001 rate order (the "2001 Settlement Order") allowed the Company to defer revenues of approximately $8.5 million (the "Deferred Revenues"), generated by leveling winter/summer rates during 2001, to help offset costs and realize our allowed rate of return during the 2001-2003 period. The 2003 Rate Plan permitted us to continue to defer and recognize these revenues in 2004. We recognized approximately $3.0 million of the Deferred Revenues in 2004. At December 31, 2004, the Company had recognized all the Deferred Revenues.

Power supply expenses were equivalent to approximately 63 percent of total revenues in the third quarter of 2005. 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 included in the rates we charge our customers.

Company forecasts presently indicate the need for a rate increase of approximately 13 percent in 2007 to achieve our allowed rate of return, caused principally by forecasted higher replacement energy costs upon expiration of the Company's power supply contract with Morgan Stanley Capital Group, Inc. on December 31, 2006, increased energy costs for uncovered load obligations and a forecasted increase in transmission expense. Forecasted amounts could change materially based on energy prices, the timing of transmission investments and other factors. The Company is exploring alternatives designed to mitigate the magnitude of this potential rate increase, including alternative regulation and power supply contract options. The Company expects the customers of many other New England utilities to experience similar cost pressures in light of current wholesale energy prices.

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 its 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 contingency reserves; 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, forecasts, 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, timing 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
- performance of equity investments in pension assets

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.

Total basic earnings per share of Common Stock	Three months ended September 30		Nine months ended September 30	
	2005	2004	2005	2004
Utility business	$ 0.49	$ 0.66	$ 1.50	$ 1.72
Unregulated businesses	0.00	0.01	0.02	0.04
Earnings per share of common stock	$ 0.49	$ 0.67	1.52	1.76
Basic earnings per share	$ 0.49	$ 0.67	$ 1.52	$ 1.76
Diluted earnings per share	$ 0.48	$ 0.65	$ 1.50	$ 1.70

Operating Results

The Company had consolidated earnings of $0.48 per share of common stock, diluted, for the third quarter of 2005 compared with consolidated earnings of $0.65 per share of common stock, diluted, for the same period in 2004.

Earnings declined in the third quarter of 2005 primarily as a result of higher power supply, other operating and transmission expenses partially offset by an increase in retail revenues. The earnings decline in 2005 was caused in large part by significantly higher wholesale energy prices.

The Company has long-term, essentially fixed-price, power supply contracts that cover over 90 percent of customer demand under normal weather conditions. Nonetheless we were exposed to higher energy prices in the third quarter of 2005, including lost margins on incremental sales, increased costs of energy lost over the transmission system (line losses) and higher allocated costs from ISO New England for congestion and other ancillary energy services. Hurricanes Katrina and Rita and a very hot summer sent New England wholesale electricity prices sharply higher in the third quarter.

The Vermont Public Service Board issued an order in December 2003 allowing the Company to carry unused deferred revenue totaling approximately $3.0 million to 2004 and to recognize this revenue to achieve its allowed rate of return during 2004. During the third quarter of 2004, the Company’s earnings benefited by $0.05 per share as a result of recognizing deferred revenues, compared with no recognition of deferred revenue during the same period of 2005. A rate increase of 1.9 percent effective in January 2005 resulted in the replacement of deferred revenues with cash revenues and has contributed to strong cash flows in 2005.

Retail operating revenues for the third quarter of 2005 increased by $6.4 million compared with the same period in 2004, reflecting the effects of warmer summer weather, increased sales of utility services to other municipalities and utilities, a 1.9 percent rate increase and an increase in the number of customers. Total retail megawatt hour sales of electricity increased by 6.6 percent in the third quarter of 2005, compared with the same period in 2004. Sales to residential and small commercial and industrial customers increased by 13.4 percent and 8.2 percent, respectively, compared with the third quarter in 2004. By contrast, sales to large commercial and industrial customers decreased by 0.2 percent in the third quarter of 2005 compared with the same quarter last year. Increased revenues from the sale of utility services to other utilities and large industrial customers in the third quarter of 2005 also contributed approximately $2.1 million to retail revenue growth, when compared to the same period last year. Other operating expenses increased by $1.9 million in the third quarter of 2005, reflecting an increase of $1.7 million in utility services expense. These sales of services are intended to allow the Company to recover a portion of its administrative and general and staffing costs from other parties and ultimately reduce costs to customers. Wholesale revenues in the third quarter of 2005 increased by $2.3 million compared with the third quarter of 2004, reflecting higher energy prices.

Power supply expenses increased $6.3 million in the third quarter of 2005 compared with the same quarter of 2004 due to increased costs of market purchases to serve marginal load, and increased costs of transmission line losses and congestion costs allocated within the New England power pool by ISO New England. Congestion charges represent the cost of delivering energy to customers and reflect energy prices, customer demands, and the availability of transmission and generation resources. The Company paid an average market price of approximately $103 per megawatt hour for system purchases during hours when customer demand exceeded supply during the third quarter of 2005, compared to $41 per megawatt hour in the same period last year, inclusive of the effects of congestion and line losses.

Transmission expenses increased by $600,000 in the third quarter of 2005 compared with the same period last year, primarily as a result of increased energy purchases. The Company's future growth will benefit from expanded transmission investment by VELCO, principally for the construction of high voltage transmission lines in Vermont. The Northwest Reliability Project is the most significant component of that expanded investment. The VPSB has issued a certificate of public good for the project and VELCO has begun construction of this project.

The Company recorded diluted earnings per share of $1.50 for the nine months ended September 30, 2005, compared with diluted earnings per share of $1.70 in the same period last year. Earnings decreased in 2005 principally because of energy price increases and increased transmission expenses, other operating expenses, and depreciation and amortization expenses. These increases in expenses more than offset the benefits of increased retail sales of electricity.

Transmission expenses increased by approximately $1.5 million in the first nine months of 2005 compared with the same period last year, reflecting an increase in charges allocated for system support in New England by ISO New England and additional transmission investment by VELCO.

Other operating expenses increased by approximately $2.6 million in the nine months of 2005 compared with the same period of 2004 due primarily to a $2.2 million increase in expenses associated with the sale of utility services and regulatory expenses. These expenses were substantially offset by an increase of $2.4 million in retail revenue from the sale of these services.

Energy prices rose substantially in 2005, principally in the third quarter. The increase in energy prices caused lost margins on retail sales and an increase in transmission line losses and congestion costs allocated within the New England power pool by ISO-NE, when compared with the first nine months of 2004.

Depreciation and amortization expenses increased by approximately $848,000 in the first nine months of 2005 as a result of increased investment in utility plant and increased amortization of regulatory assets, when compared with the same period during 2004.

During the nine month period ended September 30, 2004, the Company reversed operating reserves totaling approximately $700,000, based upon management's assessment that the contingencies reserved for were no longer probable of occurring.

OPERATING REVENUES AND MWh SALES

Our revenues from operations, megawatt hour ("MWh") sales and average number of customers for the three and nine months ended September 30, 2005 and 2004 are summarized below:

	Three months ended September 30		Nine months ended September 30	
Dollars in thousands	2005	2004	2005	2004
Operating revenues				
Retail	$ 57,584	$ 51,224	$ 162,874	$ 154,838
Sales for Resale	6,740	4,443	14,586	19,220
Total Operating Revenues	$ 64,324	$ 55,667	$ 177,460	$ 174,058

MWh Sales-Retail	525,783	493,135	1,508,825	1,469,090
MWh Sales for Resale	74,139	93,833	209,017	347,453
Total MWh Sales	599,922	586,968	1,717,842	1,816,543

Average Number of Customers

	Three months ended September 30		Nine months ended September 30	
	2005	2004	2005	2004
Residential	76,316	75,253	76,162	75,341
Commercial and Industrial	13,658	13,480	13,708	13,476
Other	60	62	61	62
Total Number of Customers	90,034	88,795	89,931	88,879

Revenues

Total operating revenues in the third quarter of 2005 increased by $8.7 million or 15.6 percent from the same period in 2004, consisting of an increase in retail revenues of $6.4 million and an increase in wholesale revenues of $2.3 million. Most of the Company's earnings result from retail sales of electricity.

Retail operating revenues for the third quarter of 2005 increased $6.4 million or 12.4 percent compared with the same period in 2004, reflecting increased megawatt hour sales of electricity caused by warmer summer weather, increased revenues from the sale of utility construction services, a 1.9 percent rate increase under the 2003 Rate Plan and an increase in the total number of customers. This increase was offset in part by a $385,000 decrease in the recognition of revenues deferred under the 2001 Settlement Order. Total retail megawatt hour sales of electricity increased by 6.6 percent in the third quarter of 2005, compared with the same period in 2004. Sales to residential and small commercial and industrial customers increased by 13.4 percent and 8.2 percent, respectively, while sales to large commercial and industrial customers declined by 0.2 percent, when comparing the third quarter of 2005 to the same period in 2004. Most of the increase in residential and small commercial and industrial consumption was related to warmer than normal summer weather.

The Company recognizes revenues from sales of utility construction services in retail revenues. Revenues from these activities amounted to $2.6 million in the third quarter of 2005 compared with $522,000 in the same period last year. Revenues from these activities are expected to increase to approximately $5 million during 2005 from $1.9 million in 2004.

Wholesale revenues increased $2.3 million or 51.7 percent during the third quarter of 2005, compared with the same period in 2004, as a result of increased energy prices.

Retail operating revenues increased $8.0 million or 5.2 percent during the first nine months of 2005, compared with the same period of 2004, reflecting an increase of approximately $2.9 million or 5.1 percent in revenues from residential customers, an increase of $2.6 million or 4.7 percent in small commercial and industrial revenues, and an increase of $1.3 million or 3.4 percent in large commercial and industrial revenues, offset by a $1.9 million decrease in the recognition of the Deferred Revenues. Other operating revenues also increased by $2.5 million reflecting increased revenues from sales of utility construction services.

Total retail MWh sales of electricity in the first nine months of 2005 increased 2.6 percent when compared with the first nine months of 2004, reflecting an increase in residential and small commercial and industrial sales of 3.9 percent, and 3.7 percent, respectively, and an increase of 0.4 percent in large commercial and industrial sales. A warmer than normal summer and an increase in the number of customers caused the increase in sales.

Wholesale revenues decreased $4.6 million or 24.1 percent during the first nine months of 2005, compared with the same period in 2004, as a result of reduced market sales.

Customer Concentration Risk

The Company’s major industrial customer, International Business Machines ("IBM"), accounted for 16.3 percent, 16.4 percent and 16.6 percent of retail revenue for 2005 year to date, 2004 and 2003, respectively. The Company currently estimates, based on current forward energy prices, that a hypothetical shutdown of the IBM facility would not require any rate increase, inclusive of projected related declines in sales to residential and commercial customers. This effect occurs because forward energy prices are well above the price at which we sell electricity to IBM.

OPERATING EXPENSES

Power supply expenses

Power supply expenses increased $6.3 million or 18.6 percent in the third quarter of 2005 compared with the same period in 2004, primarily as a result of a $6.1 million increase in market purchases for resale and increased costs of transmission line losses and congestion allocated within the New England power pool by ISO-NE. The increase in market purchases was caused by higher energy prices and increased sales of electricity. Higher energy prices resulted principally from a sharp rise occurring as hurricanes Katrina and Rita disturbed energy production in the Gulf of Mexico. A significant amount of production in the Gulf remains unavailable, and prices remain high.

Power supply expenses from VYNPC decreased $227,000 or 2.6 percent during the third quarter of 2005 compared with the same period of 2004, primarily due to a declines in the price of Vermont Yankee energy purchased under our contract with VYNPC.

Company-owned generation expenses decreased $255,000 or 15.5 percent in the third quarter of 2005 compared with the same period in 2004, primarily due to decreased production at peak generation facilities, partially offset by higher fuel prices. 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 increased $6.3 million or 26.5 percent in the third quarter of 2005 compared with the same period in 2004, primarily due to increased market purchases caused by sharply higher energy prices and increased retail sales of electricity.

The Independent System Operator for New England ("ISO-NE") was created to manage the New England power pool. ISO-NE implemented its Standard Market Design ("SMD") plan governing wholesale energy sales in New England 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. Transmission projects, such as the recently approved Northwest Reliability Project ("NRP"), will reduce congestion when they are completed. The NRP is not expected to be completed prior to 2007. Even though Vermont utilities share a zone price for specific energy resources, congestion can cause a material difference to arise between the credit received at a generating point or node, (for example, entitlements to Vermont Yankee at the Vermont Yankee node) and the price that must be paid to serve Vermont load. ISO-NE allocates congestion charges to New England utilities according to its load model results.

ISO-NE supports locational capacity payments (“LICAP”) to generators in an effort to differentiate the price generators receive for capacity at different locations within New England. ISO-NE believes that proposed higher capacity payments in constrained areas will encourage the development of new generation where needed. ISO-NE has petitioned FERC for approval of LICAP at levels that are expected to result in substantially higher capacity payments to generators beginning January 1, 2006. The changes have been disputed by numerous parties for a variety of reasons. FERC has not yet approved ISO-NE’s LICAP proposal. In October 2005, FERC initiated a settlement process to consider alternatives to the LICAP proposal Under ISO-NE's LICAP proposal, Vermont is expected to fare better than many New England states since Vermont has not restructured and many of its utilities, including the Company, have specified power supply resources that meet their present needs. Therefore, requirements for capacity in Vermont would largely consist of obtaining resources for incremental as opposed to existing load. Even incrementally, future LICAP amounts for load growth beyond 2006 could be material, and if so, would be expected to increase Company rate requirements accordingly.

Power supply expenses increased $1.3 million or 1.2 percent in the first nine months of 2005 compared with the same period in 2004, primarily as a result of a $3.2 million increase in the cost of power we purchase from others, and a $2.6 million increase in power supply expenses from VYNPC that was partially offset by a $4.6 million decline in wholesale sales of electricity.

Power supply expenses from VYNPC increased $2.6 million or 11.3 percent during the first nine months of 2005 compared with the same period of 2004, primarily due to an increase in energy provided under the Power Purchase Agreement between VYNPC and ENVY, because of plant outages that occurred in 2004.

Company-owned generation expenses decreased $759,000 or 14.9 percent in the first nine months of 2005 compared with the same period in 2004, because peaking facilities were used less for reliability and economic reasons.

The cost of power that we purchased from other companies decreased $3.2 million or 3.9 percent in the first nine months of 2005 compared with the same period in 2004, primarily due to increased market purchases caused by sharply higher energy prices and increased retail sales of electricity.

Other operating expenses
Other operating expenses increased $1.9 million or 36.9 percent in the third quarter of 2005 compared with the same period in 2004 due primarily to increased expenses associated with the sale of utility services and regulatory expenses. Other operating expenses increased $2.6 million or 18.0 percent in the first nine months of 2005 compared with the same period in 2004 for the same reason.

Transmission expenses
Transmission expenses increased by approximately $598,000 or 17.2 percent for the three months ended September 30, 2005 compared with the same period in 2004, due primarily to an increase in charges allocated for system support in New England by the ISO-NE. Transmission expenses increased by approximately $1.5 million or 13.3 percent for the nine months ended September 30, 2005 compared with the same period in 2004 for the same reason.

Maintenance expenses
Maintenance expenses increased $391,000 or 16.0 percent for the three months ended September 30, 2005 compared with the same period in 2004, primarily due to an increase in plant maintenance at joint-owned and peaking facilities. Maintenance expenses increased $724,000 or 10.1 percent for the nine months ended September 30, 2005 compared with the same period in 2004 for the same reason.

Depreciation and amortization expenses
Depreciation and amortization expenses for the quarter ended September 30, 2005 increased $291,000 or 8.4 percent compared with the same period in 2004, reflecting an increase in the depreciation of utility plant due to increased investment, and the amortization of regulatory assets in accordance with the 2003 Rate Plan. Depreciation and amortization expenses increased $848,000 or 8.1 percent for the nine months ended September 30, 2005 compared with the same period in 2004 for the same reasons.

Taxes other than income taxes
Other tax expense for the third quarter of 2005 increased by $169,000 or 12.4 percent compared with the same period in 2004 due to increases in property taxes. Other tax expense for the first nine months of 2005 increased by $61,000 or

1.3 percent compared with the same period in 2004 due to gross revenue taxes on increased revenues.

Income taxes

Income taxes decreased $254,000 or 22.1 percent in the third quarter of 2005 compared with the same period in 2004 due to a decrease in pretax book income. Income taxes decreased $420,000 or 9.9 percent in the first nine months of 2005 compared with the same period in 2004 due to a decrease in pretax book income. The Company expects to recognize an income tax benefit of approximately three cents per share as a result of an income tax credit and deduction available in 2005 under the American Jobs Creation Act of 2004. The credit and deduction arise from our ownership interest in a biomass generation plant and from the production of electricity at Company hydro and fossil fuel plants.

Interest Charges

Interest charges increased $83,000 or 5.2 percent in the third quarter of 2005 compared with the same period in 2004, due to a decrease in interest capitalized on utility plant construction. Interest charges increased $192,000 or 4.0 percent in the first nine months of 2005 compared with the same period in 2004, for the same reason.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2004, we had cash and cash equivalents of $1.7 million. In the first nine months of 2005, cash and cash equivalents increased to $1.8 million. Operating cash flows decreased by $149,000 from the same period last year primarily as the result of increased working capital needs and a decrease in income from continuing operations that were offset by a rate increase that substantially replaced deferred revenue recognition and increases in depreciation and amortization. Net cash used by investing activities amounted to $15.2 million, principally for investments to construct utility plant. We expect to spend approximately $9.8 million during the remainder of 2005, primarily for improvements in transmission, distribution and generation plant, and environmental expenditures. The Company plans to invest up to $32 million in VELCO through 2009 in support of the NRP and other transmission projects, including a $4.8 million investment made in the last quarter of 2004. Our investment projections for VELCO have increased from previous estimates primarily as a result of increases in VELCO's cost estimates for the NRP.

On February 14, 2005, the annual dividend rate was increased from $0.88 to $1.00 per share, a payout ratio of approximately 48 percent based on 2004 earnings from continuing operations. 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 to the middle of a payout ratio that falls between 50 percent and 70 percent of anticipated earnings, so long as financial and operating results permit. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles. The Company expects to increase the annual dividend by 12 cents per share beginning in the first quarter of 2006, consistent with our dividend growth policy over the last few years, so long as financial and operating results permit.

We expect most of our construction expenditures and dividends to be financed by net cash provided by operating activities. Material risks to cash flow from operations include increases in net power costs, regulatory risk, and unfavorable economic conditions. We anticipate that we will issue long-term debt of up to $30 million in 2006 for scheduled first mortgage bond redemptions of $14 million and to finance increased investment in VELCO and generation. The Company has no plans at present to issue additional equity and seeks to maintain equity at between fifty and fifty-five percent of its capital structure.

During June 2005, the Company renegotiated a 364-day revolving credit agreement with Bank of America, joined by Sovereign Bank (the "BOA-Sovereign Agreement"). The BOA-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 short-term debt outstanding in the BOA-Sovereign Agreement at September 30, 2005, compared with $3.0 million outstanding at December 31, 2004. The BOA-Sovereign Agreement expires June 14, 2006.

The credit ratings of the Company's first mortgage bonds at September 30, 2005 were:

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

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

On November 3, 2004, Standard and Poor's Ratings Services upgraded the Company's issuer credit rating to BBB from BBB-.

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 and ISO-NE require credit assurances if the Company's first mortgage bond credit ratings are lowered to below investment grade by any one of the two credit rating agencies listed above.

The following table presents a summary of certain material contractual obligations existing as of September 30, 2005, for which undiscounted future annual payments are shown.

In thousands	Payments Due by Period as of September 30, 2005				
	Total	2005	2006 and 2007	2008 and 2009	After 2009
Long-term debt	$ 93,000	$ -	$ 14,000	$ -	$ 79,000
Interest on long-term debt	65,808	2,172	12,068	11,068	40,500
Capital lease obligations	4,363	143	879	766	2,575
Hydro-Quebec power supply contracts	538,486	13,219	103,169	102,723	319,375
Morgan Stanley Contract	14,937	4,780	10,157	-	-
Independent Power Producers	172,091	4,779	33,923	32,808	100,581
Stony Brook contract	44,347	415	6,024	6,506	31,402
VYNPC PPA	229,737	7,196	68,090	71,590	82,861
Total	$ 1,162,769	$ 32,704	$ 248,310	$ 225,461	$ 656,294

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.

Other Commitments - We have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments and Related Risks" 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, Legislation 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;
- consolidation through business combinations;
- new regulations and legislation intended to foster competition, ;
- changes in rules governing wholesale electricity markets; and
- increasing volatility of wholesale market prices for electricity.

Vermont is the only state in the New England region that has not adopted some form of electric industry restructuring. The Vermont legislature enacted a bill that would impose renewable portfolio standards ("RPS") on Vermont electric distribution utilities. The bill currently contemplates that, effective January 1, 2013, distribution utilities will be required to supply all load growth for 2005 - 2013 with "renewable" energy supply, as defined in the bill. The bill provides the alternative that if in-state renewable generation sufficient to supply statewide load growth for 2005 - 2013 becomes operational before 2012, and if Vermont distribution utilities acquire the output of these facilities, the RPS requirement would be avoided.

Power Contract Commitments and Related Risks
A primary factor affecting future operating results is the volatility of the wholesale electricity market. 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.

We have developed 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 remains exposed to very volatile energy markets for the remaining 10 percent of its load requirements, as well as congestion, line loss and other ancillary service charges allocated to New England utilities by ISO-NE.

Vermont does not have a fuel or purchased-power adjustment clause that would allow increases in power supply costs to be recovered immediately in the rates we charge customers. Historically, however, the VPSB has allowed electric utilities to defer material unexpected increases in power supply costs to future periods to permit recovery in future rates. Vermont law also allows electric utilities to seek temporary rate increases if deemed necessary by the VPSB to provide adequate and efficient service or to preserve the viability of the utility.

Vermont Yankee - We have a 20 percent entitlement in Vermont Yankee plant output sold by Entergy to Vermont Yankee Nuclear Power Corporation ("VYNPC"), through a long-term purchase contract with VYNPC (the "VYNPC Contract"). We generally purchase between 35 and 40 percent of our annual load requirements from VYNPC at rates that are presently well below market. We are responsible for the purchase of replacement power to serve our load requirements when the plant is not operating due to scheduled or unscheduled outages. In the first nine months of 2005, we purchased $25.9 million from VYNPC based on our entitlement share of plant output, compared to $23.2 million for the same period in 2004, reflecting 2004 scheduled and unscheduled plant outages.

Hydro Quebec - We purchase varying amounts of power from Hydro Quebec under the Vermont Joint Owners ("VJO") Contract negotiated between the Company and Hydro Quebec. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro Quebec, the remaining VJO participants, including the Company, must "step-up" to the defaulting party's share on a pro rata basis. The Company is not aware of any instance where this provision has been invoked by Hydro Quebec. In the first nine months of 2005, we purchased $34.9 million of energy and related capacity from Hydro Quebec, compared to $33.8 million for the same period in 2004.

Under the VJO Contract, Hydro Quebec had 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 its third and last option in 2004 for deliveries occurring principally during 2005. Hydro Quebec retains the right to reduce the load factor by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. The utilities that comprise the VJO retain two options to increase or reduce the load factor by 5 percent under the VJO Contract and exercised the first of these options to increase deliveries occurring principally between November 1, 2005 and October 30, 2006. The option will provide approximately 50,000 additional off-peak megawatt hours of supply.

Morgan Stanley - We purchase approximately 16 percent of our load requirements under a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"), designed to manage some of the price risks associated with changing fossil fuel prices. The Morgan Stanley Contract price is substantially below current market prices and expires on December 31, 2006. The Company is unable to predict the price, contract duration or terms of any future power supply contracts that could replace the Morgan Stanley Contract after it expires.

Defined Benefit Plans

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 expects to contribute approximately $2.0 million to defined benefits plans during 2005, of which $1.5 million has been contributed to date.

Power Supply Derivatives

The Morgan Stanley Contract 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"). Management has estimated the fair value of the future net benefit of this agreement at September 30, 2005 to be approximately $7.8 million.

We currently have an agreement that grants Hydro Quebec an option (the "9701 agreement") to call power at prices that are expected to be below estimated future market rates. This agreement is a derivative and is effective through 2015. Management’s estimate of the fair value of the future net cost for the 9701 agreement at September 30, 2005 is approximately $30.6 million. Hydro-Quebec has exercised its 9701 option for delivery during the first quarter of 2006, when market prices are currently projected to be approximately $180 per MWh. Prices are expected to be substantially higher in January and February than during the remainder of the year, reflecting hurricane activity in the Gulf of Mexico that has shut down a significant amount of natural gas production. Natural gas availability drives electricity pricing. The Company expects to ask the VPSB for an accounting order to defer 2006 incremental costs related to the run-up in energy prices, including the energy price effects on the 9701 agreement.

The table below presents the Company’s market risk of the Morgan Stanley Contract and the 9701 agreement 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 $2.7 million. 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	September 30, 2005

In thousands		Fair Value(Cost)		Market Risk
Morgan Stanley Contract	$	22,826	$	3,533
9701 agreement		(30,591)		(3,977)
	$	(7,765)	$	(444)

New Accounting Standards
See Part I-Item 1, Note 5, "New Accounting Standards" for information on the adoption of new accounting standards and the impact, if any, on the Company's financial position and operating results.

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.

Management’s report on the Company’s internal control over financial reporting was included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2004 and concluded that, as of December 31, 2004, the Company did not maintain effective internal control over financial reporting due to a material weakness as a result of deficiencies in both the design and operating effectiveness of controls associated with the Company’s accounting for income taxes. During the first nine months of 2005, management conducted testing and enhancement of the Company’s internal controls associated with accounting for income taxes and engaged a public accounting firm to assist management with its review of all income tax entries for the quarter, the statutory rate reconciliation, the Company's treatment of new tax credits and deductions, if applicable, and timing differences. These ongoing efforts, which required certain changes to the Company’s internal controls associated with accounting for income taxes, and which are subject to audit by the Company’s independent registered accounting firm at year-end, have improved the design and operational effectiveness of the Company's control processes and systems for financial reporting. Based on these efforts, management believes that the deficiencies in both the design and operating effectiveness of controls associated with the Company’s accounting for income taxes have been remediated and that the Company no longer has a material weakness in its internal control over financial reporting. It should be noted that the design of any system of controls is based, in part, on certain assumptions about the likelihood of future events, and that only reasonable assurance can be given that any internal control system will succeed in achieving its stated goals against all potential future conditions, regardless of how remote.

Except as described above, there has been no change in our internal control over financial reporting during the quarter ended September 30, 2005, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting

GREEN MOUNTAIN POWER CORPORATION
September 30, 2005
PART II - OTHER INFORMATION

Item 1.
Legal Proceedings
See Note 3 of Notes to Consolidated Financial Statements
Item 2.
Unregistered Sales of Equity Securities and Use of Proceeds
NONE
Item 3.
Defaults Upon Senior Securities
NONE
Item 4.
Submission of Matters to a Vote of Security Holders
NONE
Item 5.
Other Information
NONE
ITEM 6.
Exhibits

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, Treasurer and Principal Accounting 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 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 Treasurer and Principal Accounting Officer 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.

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	
By: /s/ Christopher L. Dutton	November 9, 2005
Christopher L. Dutton	Date
President and Chief Executive Officer	
By: /s/ Robert J. Griffin	November 9, 2005
Robert J. Griffin	Date
Vice President, Chief Financial Officer and Treasurer and Principal Accounting Officer	